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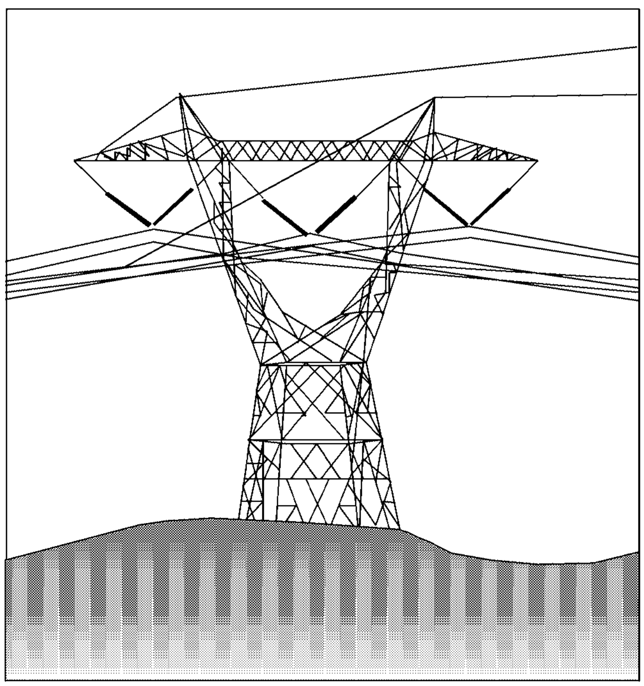
2004 FINAL TRANSMISSION PROPOSAL

REVENUE REQUIREMENT STUDY

TR-04-FS-BPA-01



MAY 2003

Bonneville Power Administration
Transmission Business Line

2004 Final Transmission Proposal

Revenue Requirement Study

TR-04-FS-BPA-01

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1. INTRODUCTION

1.1 Purpose and Development of the Revenue Requirement Study

The purpose of the Revenue Requirement Study (Study) is to establish the level of revenues needed from rates for transmission and ancillary services to recover, in accordance with sound business principles, costs associated with the transmission of electric power over the Federal Columbia River Transmission System (FCRTS). The transmission revenue requirements herein include: recovery of the Federal investment in transmission and transmission-related assets; the operations and maintenance (O&M) and other annual expenses associated with transmission and ancillary services; the cost of generation inputs for ancillary services and other interbusiness-line services necessary for the transmission of power; and all other transmission-related costs incurred by the Administrator.

The cost evaluation period for this rate proposal includes Fiscal Years (FY) 2003 - 2005, the period extending from the last year for which historical information is available through the proposed rate test period. The Study is based on transmission revenue requirements for the rate test period FY 2004 – 2005, including the results of transmission repayment studies. This Study does ***not*** include revenue requirements or a cost recovery demonstration for the Bonneville Power Administration's (BPA) generation function.

This Study outlines the policies, forecasts, assumptions, and calculations used to determine BPA's transmission revenue requirements. Legal requirements are summarized in Chapter 5 of this Study. The Revenue Requirement Study Documentation (Documentation), TR-04-FS-BPA-01A, contains key technical assumptions and calculations, the results of the transmission repayment studies, and a further explanation of the repayment program and its outputs.

The revenue requirements that appear in this Study are developed using a cost accounting analysis comprised of three parts. First, repayment studies for the transmission function are prepared to determine the amortization schedule and to project annual interest expense for bonds and appropriations that fund the Federal investment in transmission and transmission-related assets. Repayment studies are conducted for each year of the rate test period, and cover a 35-year repayment period. Second, transmission operating expenses and minimum required net revenues (if needed) are projected for each year of the rate test period. Third, the necessity for including annual planned net revenues for risk is determined taking into account risks, BPA's cost recovery goals, and risk mitigation measures. From these three steps, revenue requirements are set at the revenue level necessary to fulfill BPA's cost recovery requirements and objectives. *See* Figure 1, Transmission Revenue Requirement Process.

BPA conducts a current revenue test to determine whether revenues projected from current rates meet its cost recovery requirements and objectives for the rate test and repayment period. If the current revenue test indicates that cost recovery and risk mitigation requirements can be met, current rates could be extended. The current revenue test, discussed in Chapter 4.2, demonstrates that current revenues are insufficient to meet cost recovery requirements and objectives for the rate test period and the repayment period.

Consistent with Department of Energy Order RA 6120.2 and the Federal Energy Regulatory Commission (FERC) rate review standards applicable to BPA, BPA must demonstrate the adequacy of the proposed rates to recover its costs. The revised revenue test determines whether projected revenues from proposed rates will meet cost recovery requirements and objectives for the rate test and repayment period. The revised revenue test, discussed in Chapter 4.3, demonstrates that revenues from the proposed transmission and ancillary services rates will recover transmission costs in each year of the rate test period and over the ensuing 35-year repayment period. Consistent with the Treasury payment probability (TPP) standard that was adopted as a long-term policy in 1993, the costs are projected to be recovered through the transmission and ancillary services rates with a greater than 95 percent probability that associated United States (U.S.) Treasury payments will be made on time and in full over the two-year rate period. *See* Chapter 2.2.

Table 1 summarizes the revised revenue test and shows projected net revenues from proposed rates over the two-year rate period. In combination with other risk mitigation tools, these net revenues are set at the lowest level necessary to achieve BPA's cost recovery objectives in the face of transmission-related risks. Table 2 shows planned transmission amortization repayments to the U.S. Treasury during the rate test period.

1.2 Public Involvement Process

Concurrent with, but independent of preparing this rate proposal, BPA conducted a public process, Programs in Review, to get input from customers and constituents about planned capital spending and the expenses associated with supporting a reliable and safe transmission system. The results of these public meetings contributed to the Administrator's decisions on TBL expense and capital spending levels for the FY 2004-2005 rate period. *See* Chapter 2. The Administrator's decisions have been reflected in the revenue requirements, including repayment studies, in this rate proposal.

2. SPENDING LEVEL DEVELOPMENT AND FINANCIAL POLICY

2.1 Development Process for Spending Levels

In July 2002, BPA began a public involvement process entitled "Programs in Review." The purpose of Programs in Review (PIR) was to review and discuss transmission program spending levels for FY 2004 through FY 2006. PIR was designed to provide the region an overview of, and context for major policy issues surrounding the Transmission Business Line's (TBL's) expense and capital programs. The PIR process helped establish the following goals:

(1) Assure that rates will not rise, or that they will rise to some minimum level through effective and efficient management of expense and capital program costs;

(2) Assure that there will be no shift in costs or risks with the building of infrastructure projects associated with integration of new generation projects and that those who receive the benefit are being appropriately charged; and

(3) Manage the transmission system with sufficient resources and program levels to assure transmission system reliability and availability to meet the challenges of a competitive and dynamic market place.

BPA conducted five regional workshops, beginning in July 2002, to ask for customer input during the PIR public process. At the customers' request, an additional workshop was held in Portland in September 2002 so staff could provide details of the proposed program levels. The public process solicited customer comments on TBL's proposed FY 2004 through 2006 spending levels for transmission system operations, maintenance and construction. Projected costs for FY 2002 and FY 2003 were also presented. This forum included a detailed discussion of capital spending levels and planned transmission system improvements, upgrades and reinforcement projects.

TBL's capital proposal was also reviewed through the established Regional Technical Review Teams to better define the prioritization, costs and need for transmission projects. With input from the Regional Technical Review Teams, TBL identified capital investments that are necessary to:

(1) Meet existing contractual requirements and increased wholesale transmission transactions, reliably serve load growth, provide reactive needs, new generation reinforcements and system replacements, alleviate constrained paths, and respond to changes in reliability criteria;
(2) Replace aging equipment and maintain the system in a safe, reliable, environmentally responsible, and cost-effective manner; and
(3) Invest in technology to address significantly higher and more complex uses of BPA's transmission system.

PIR workshop participants were advised that public comments and concerns offered during the process would inform the Administrator's decision with regard to spending levels. Those spending levels serve as the basis for the revenue requirements, which are then used to set rates. Notices of the workshops were distributed widely to TBL's customers and interested parties and posted on BPA's website. Workshop participants provided substantial oral and written comments with regard to TBL's planned transmission capital spending and program expenditures.

The Administrator issued a letter on December 19, 2002, entitled "Close out of the public process and final report on the Transmission Business Line's Programs in Review regarding expense and capital spending – Fiscal Years 2004 and 2005." *See* Appendix B. The Administrator's decisions have been reflected in the revenue requirements, including repayment studies, in this rate proposal.

In the Administrator's letter, the "TBL Expense Levels" table (Appendix B, page 6) illustrates the initial PIR proposal compared to the final PIR program level decisions. TBL is holding operating cost increases to a level that is less than the rate of inflation. The table shows a $17.5 million annual transmission program expense reduction. Significant cost savings are realized in the general and administrative, operations, maintenance, development and support services programs.

For the capital program, spending levels of $327 million and $280 million are adopted for FY 2004 and FY 2005, respectively. These funding levels do not include funding requirements or risk related to integrating new generation into the transmission system. Integration of new generation is expected to move forward only if non-federal funding is secured.

2.2 Financial Risk and Mitigation

BPA adopted a long-term policy in its 1993 Final Rate Proposal that called for setting rates that build and maintain financial reserves sufficient for the agency to achieve a 95 percent Treasury payment probability (TPP) of making U.S. Treasury payments in full and on time for a 2-year rate period. *See* 1993 Final Rate Proposal, Administrator's Record of Decision, WP-93-A-02, p. 72. For further discussion of the TPP standard, see the 2002 Final Power Rate Proposal Revenue Requirement Study, WP-02-FS-BPA-02, Chapter 2, Section 2.2, p. 18; and the 2002 Final Power Rate Proposal, Administrator's Record of Decision, WP-02-A-02, pp. 7-7 to 7-16.

In this rate proposal, BPA has analyzed its transmission risks and has determined that the Final Rate Proposal achieves the 95 percent probability standard for the transmission function. To achieve this level of TPP, the following risk mitigation "tools" are considered in the rate proposal.

(1) <u>Starting reserves</u> Starting financial reserves include cash in the BPA Treasury Fund and the deferred borrowing balance attributed to the transmission function. The risk-adjusted value for starting reserves is projected to total $182 million at the beginning of FY 2004.

(2) <u>Planned Net Revenues for Risk (PNRR)</u> PNRR is a component of the revenue requirement that is added to annual expenses if reserves are not sufficient for risk

mitigation purposes. PNRR adds to cash flows so that financial reserves are sufficient to mitigate short run volatility in expenses and revenues and achieve the TPP goal. No PNRR were required to meet the TPP standard in the Final Rate Proposal.

(3) Two-Year Rate Period BPA is proposing to adopt rates for a two-year rate period. The ability to revise rates after two years, or more frequently if need be, serves as an important risk mitigation tool for BPA's transmission function. By adopting a two-year rate period, the TBL limits the amount of risk that must be covered by financial reserves and PNRR.

2.2.1 Transmission Risk Analysis

To quantify the effects of risk on the finances of BPA's transmission function, BPA analyzes the effects of uncertainty in expenses and revenues on transmission cash flows using a Monte Carlo simulation method. *See* Figure 3. The analysis is used to estimate the probability of successful Treasury payment (on time and in full) for both years of the rate period. Successful Treasury payment is deemed to occur when the end-of-year cash reserves for the transmission function, after Treasury payments are made, are sufficient to cover the transmission function's working capital requirement of $20 million. The working capital threshold is based on the monthly net cash flow patterns and requirements for the transmission function.

The risk analysis forecasts cash reserves at the beginning of the FY 2004 - 2005 rate period and estimates PNRR if reserves are not sufficient to cover risk. Initial input values for point estimates of expenses and revenues come from the Study and the revenue forecast (Documentation, TR-04-FS-BPA-01A, Chapter 13) and, when combined with inputs describing uncertainty in expenses and revenues, provides the basis for the initial estimate of PNRR. The PNRR, in turn, is provided as an expense input to the Study, changing the transmission revenue requirement and transmission rates. This iterative analysis process is continued until successive estimates of PNRR converge.

The risk analysis covers the period FY 2003 through FY 2005. This time frame is used to permit analyzing the change in revenues, expenses, and accrual-to-cash adjustments that are expected to occur between the development of the final rate proposal and the end of the rate period. The advantage to this approach is that cash reserves at the start of the next rate period (FY 2004-2005) may be estimated, including the effects of uncertainty in current rate period cash flows, thus helping define the starting conditions for the next rate period.

2.2.2 Transmission Risk Analysis Model

The foundation of the risk analysis is a transmission financial spreadsheet model. *See* Documentation, TR-04-FS-BPA-01A. This model was developed to estimate the effects of risk and risk mitigation on end-of-year cash reserves and likelihood of successful Treasury payment during the rate period. Cash reserve levels at the end of the fiscal year determine whether BPA is able to meet its Treasury payment obligation. The model contains individual work sheets including: an input matrix of revenues and expenses, an income statement, a cash flow statement, and individual work sheets for variables specified with uncertainty in the model. Parameters for the probability distributions were developed from historical data and analysis of risk factors.

2.3 Capital Funding

BPA transmission capital outlay projections for this proposal are $627.3 million for the FY 2004-2005 rate period. These investments include:

- transmission programs ($594.5 million);
- environmental program ($12.8 million);
- Corporate and TBL investments in ADP and other capital equipment ($20.0 million).

2.3.1 Bonds Issued to the Treasury

Bonds issued to the U.S. Treasury will be the primary source of capital used to finance FY 2004-2005 BPA capital program investments. Interest rates on bonds issued by BPA to the U.S. Treasury are set at market interest rates comparable to securities issued by other agencies of the U.S. Government. Interest rates on bonds projected to be issued are included in Chapter 6 of the Documentation, TR-04-FS-BPA-01A.

2.3.2 Federal Appropriations

This Study includes the original capital investments in the Federal transmission system that were financed by Federal appropriations prior to BPA self-financing status. No investments have been funded by appropriations since that time. "The Bonneville Appropriations Refinancing Act" (the Refinancing Act) was enacted in April 1996. This Refinancing Act reset the unpaid principal of FCRPS appropriations and reassigned interest rates. New principal amounts were established at the beginning of FY 1997, at the present value of the principal and annual interest payments BPA would make to the Treasury for these obligations in the absence of the Refinancing Act, plus $100 million. Before implementation of the Refinancing Act there was $1,545.7 million in BPA appropriations outstanding. After the implementation of the Refinancing Act, $1,075.4 million in BPA appropriations was outstanding. The Refinancing Act restricted prepayment of the new principal to $100 million in the FY 1997-2001 period. Other repayment terms were unaffected.

2.3.3 Revenue Financing

Revenue requirements in this rate period reflect $15 million per year as cash requirements to fund capital investments from current revenues.

3. DEVELOPMENT OF REPAYMENT STUDIES

Repayment studies are performed as the first step in determining revenue requirements. The studies establish the schedule of annual U.S. Treasury amortization for the rate test period and the resulting interest payments.

In this study, as in the previous transmission rate filing, the repayment period has been set at 35 years. This study horizon reflects the fact that bonds are not issued for terms longer than 35 years and that the outstanding appropriations and bonds in the transmission system are fully repaid within this period. It also is consistent with the estimated average service life of transmission system plant (40 years) in that it does not exceed that average lifetime. The Revenue Requirement Study includes the results of transmission repayment studies for each of the two years in the rate test period, FYs 2004 and 2005. In conducting the repayment studies, BPA includes outstanding and projected transmission repayment obligations on appropriations and on bonds issued to the U.S. Treasury. Funding for replacements projected during the repayment period also is included in the repayment study, consistent with the requirements of RA 6120.2. *See* Chapter 5.

Historical appropriations are scheduled to be repaid within the expected useful life of the associated facility or 50 years, whichever is less. Actual bonds issued by BPA to the Treasury may be for terms ranging from 3 to 40 years, taking into account the estimated average service lives for investments and prudent financing and cash management factors. In the repayment studies, all projected bonds have a term of 35 years for transmission investment and 15 years for environment investment. Many bonds are issued with a provision that allows the bond to be called after a certain time, typically five years. Bonds also may be issued with no early call provision. Early retirement of eligible bonds requires that BPA pay a bond premium to the Treasury. The premium that must be paid decreases with the age of the bond, and is equivalent, in total, to a fixed premium and a reduced interest rate. This reduced effective interest rate enters into the comparison with other Federal investments and obligations to determine which should be repaid first. Bonds are issued to finance BPA transmission and environment investments and are repaid within the provisions of each bond agreement with the Treasury.

Based on these parameters, the repayment study establishes a schedule of planned amortization payments and resulting gross interest expense by determining the lowest levelized debt service stream necessary to repay all transmission obligations within the required repayment period.

Further discussion of the repayment program and repayment program tables is included at Appendix A; and in Chapter 12 of the Documentation, TR-04-FS-BPA-01A. *See* Chapter 5 of this Study, for an explanation of repayment policies and requirements.

4. TRANSMISSION REVENUE REQUIREMENTS

This chapter explains the cost accounting formats used to develop revenue requirements for FYs 2004 and 2005. Section 4.1.1 provides a line-by-line description of the Revenue Requirement Income Statement and Section 4.1.2 provides a line-by-line description of the Revenue Requirement Statement of Cash Flows.

4.1 Revenue Requirement Format

For each year of a rate test period, BPA prepares two tables that reflect the process by which revenue requirements are determined. The Income Statement includes projections of Total Expenses, Planned Net Revenues for Risk, and, if necessary, a Minimum Required Net Revenues component. The Statement of Cash Flows shows the analysis used to determine Minimum Required Net Revenues and the cash available for risk mitigation.

The Income Statement (Table 3) displays the components of the annual revenue requirements, which include Total Operating Expenses (Line 5), Net Interest Expense (Line 14), Minimum Required Net Revenues (Line 16), and Planned Net Revenues for Risk (Line 17). The sum of these four major components is the Total Revenue Requirement (Line 19).

The Minimum Required Net Revenues (Line 16) result from an analysis of the Statement of Cash Flows (Table 4). Minimum Required Net Revenues may be necessary to ensure that revenue requirements are sufficient to cover all cash requirements, including annual amortization of the Federal investment as determined in the transmission repayment studies.

The Statement of Cash Flows analyzes annual cash inflows and outflows. Cash Provided by Current Operations (Line 8), driven by the Non-cash Expenses shown in Lines 4, 5 and 6, must be sufficient to compensate for the difference between Cash Used for Capital Investments (Line 12) and Cash From Treasury Borrowing (Line 17). If cash provided by Current Operations is not sufficient, Minimum Required Net Revenues must be included in revenue requirements to accommodate the shortfall, yielding at least a zero annual Increase in Cash (Line 18). The Minimum Required Net Revenues shown on the Statement of Cash Flows (Line 2) then is incorporated in the Income Statement (Line 16).

4.1.1 Income Statement

Below is a line-by-line description of the components in the Income Statement (Table 3). The Documentation, TR-04-FS-BPA-01A, provides additional information on the development and use of the data contained in the tables.

Operation & Maintenance (Line 2). Operation & Maintenance represents FCRTS O&M expenses incurred by BPA. Specific BPA O&M expenses include transmission scheduling, transmission marketing, transmission system operations, transmission system maintenance, transmission system development, environment, non-Federal transmission arrangements, leases, TBL general and administrative, TBL support services, Civil Service Retirement System pension expense, and corporate administrative and support services. *See* Chapter 2, Documentation, TR-04-FS-BPA-01A

Inter-Business Line Expenses (Line 3). Inter-business line expenses, resulting from functional separation and ancillary services products, include the generation inputs to ancillary services from the PBL, station service and remedial action schemes, and the cost of Corps of Engineers and Bureau of Reclamation transmission facilities serving the network and utility delivery segments. *See* Chapter 2, Documentation, TR-04-FS-BPA-01A.

Federal Projects Depreciation (Line 4). Depreciation is the annual capital recovery expense associated with FCRTS plant-in-service. BPA transmission and general plant are depreciated by the straight-line method of calculation, using the remaining life technique. *See* Chapter 3, Documentation, TR-04-E -BPA-01A.

Total Operating Expenses (Line 5). Total Operating Expenses is the sum of the above expenses (Lines 2 through 4).

Interest on Appropriated Funds (Line 8). Interest on Appropriated Funds consists of interest on the appropriations BPA received prior to self-financing status and is determined in the transmission repayment studies. *See* Chapter 2, Documentation, TR-04-FS-BPA-01A.

Interest on Long-Term Debt (Line 9). Interest on long-term debt includes interest on bonds that BPA issues to the Treasury to fund investments in transmission plant, environment, general plant supportive of transmission, and capital equipment. Such interest expense is determined in the transmission repayment studies. Any payments of premiums for bonds projected to be amortized are included in this line. Also included is an interest income credit calculated in the transmission repayment studies on funds to be collected during each year for payments of Federal interest and amortization at the end of the fiscal year. A further explanation of the calculation of the interest credit computed within the transmission repayment studies is included in Appendix A. *See* Chapter 2, Documentation, TR-04-FS-BPA-01A.

Interest Credit on Cash Reserves (Line 10). Interest income also is computed on the projected year-end cash balances in the BPA fund attributable to the transmission function that carry over into the next year. It is credited against bond interest. *See* Chapter 4, Documentation, TR-04-FS-BPA-01A.

Amortization of Capitalized Bond Premiums (Line 11). When a bond issued to the Treasury is refinanced, any call premium resulting from early retirement of the original bond is capitalized and included in the principal of the new bond. The capitalized call premium then is amortized over the term of the new bond. The annual amortization is a non-cash component of interest expense. *See* Chapter 2, Documentation, TR-04-FS-BPA-01A.

Capitalization Adjustment (Line 12). Implementation of the Refinancing Act entailed a change in capitalization on BPA's financial statements. Outstanding appropriations attributed to the transmission function were reduced by $470 million as a result of the refinancing. The reduction is recognized annually over the remaining repayment period of the refinanced appropriations. The annual recognition of this adjustment is based on the increase in annual interest expense resulting from implementation of the Act, as shown in repayment studies for the year of the refinancing transaction (1997). The capitalization adjustment is included on the income statement as a non-cash, contra-expense. *See* Chapter 2, Documentation, TR-04-FS-BPA-01A.

Allowance for Funds Used During Construction (AFUDC) (Line 13). AFUDC is a credit against interest on long-term debt (Line 9). This non-cash reduction to interest expense reflects an estimate of interest on the funds used during the construction period of facilities that are not yet in service. AFUDC is capitalized along with other construction costs and is recovered through rates over the expected service life of the related plant as part of the depreciation expense after the facilities are placed in service.

Net Interest Expense (Line 14). Net Interest Expense is computed as the sum of Interest on Appropriated Funds (Line 8), Interest on Long-Term Debt (Line 9), Interest Credit on Cash Reserves (Line 10), Amortization of Capitalized Bond Premiums (Line 11), Capitalization Adjustment (Line 12), and AFUDC (Line 13).

Total Expenses (Line 15). Total Expenses are the sum of Total Operating Expenses (Line 5) and Net Interest Expense (Line 14).

Minimum Required Net Revenues (Line 16). Minimum Required Net Revenues, an input from Line 2 of the Statement of Cash Flows (Table 4), may be necessary to cover cash requirements in excess of accrued expenses. An explanation of the method used for determining the Minimum Required Net Revenues is included in Section 4.1.2 below.

Planned Net Revenues for Risk (Line 17). Planned Net Revenues for Risk are the amount of net revenues, if any, to be included in rates for financial risk mitigation. There are no

Planned Net Revenues for Risk included in the Final Rate Proposal. Starting TBL reserves in FY 2004 are projected to be sufficient to mitigate risk in FYs 2004 and 2005.

Total Planned Net Revenues (Line 18). Total Planned Net Revenues is the sum of Minimum Required Net Revenues (Line 16) and Planned Net Revenues for Risk (Line 17).

Total Revenue Requirement (Line 19). Total Revenue Requirement is the sum of Total Expenses (Line 15) and Total Planned Net Revenues (Line 18).

4.1.2 Statement of Cash Flows

Below is a line-by-line description of each of the components in the Statement of Cash Flows (Table 4). The Documentation, TR-04-FS-BPA-01A, provides additional information related to the use and development of the data contained in the cash flow table.

Minimum Required Net Revenues (Line 2). Determination of this line is a result of annual cash inflows and outflows shown on the Statement of Cash Flows. Minimum Required Net Revenues may be necessary so that the cash provided from operations will be sufficient to cover the planned amortization payments (the difference between Lines 12 and 17) without causing the Annual Increase (Decrease) in Cash (Line 18) to be negative. The Minimum Required Net Revenues amount determined in the Statement of Cash Flows is incorporated in the Income Statement (Line 16).

Federal Projects Depreciation (Line 4). Depreciation is from the Income Statement (Table 3, Line 4). It is included in computing Cash Provided By Operations (Line 8) because it is a non-cash expense of the FCRTS.

Amortization of Capitalized Bond Premiums (Line 5). Amortization of Capitalized Bond Premiums, from the Income Statement (Table 3, Line 11), is a non-cash expense.

Capitalization Adjustment (Line 6). The Capitalization Adjustment, from the Income Statement (Table 3, Line 12), is a non-cash (contra) expense.

Accrual Revenues (AC Intertie/Fiber) (Line 7). BPA accounts for the AC Intertie non-Federal capacity ownership lump-sum payments received in FY 1995 as unearned revenues that are recognized as annual accrued revenues over the estimated average service life of BPA's transmission system (straight-line over 40 years). Similarly, some of the leases of fiber optic capacity have included up-front payments, the annual accrued revenues for which are being recognized over the life of the particular contract. The annual accrual revenues, which are part of the total revenues recovering the FCRTS revenue requirement, are included here as a non-cash adjustment to cash from current operations.

Cash Provided By Current Operations (Line 8). Cash Provided By Current Operations, the sum of Lines 2, 4, 5, 6 and 7, is available for the year to satisfy cash requirements.

Investment in Utility Plant (Line 11). Investment in Utility Plant represents the annual increase in capital spending related to additions and replacements to plant-in-service for BPA. *See* Chapter 2 of this Study.

Cash Used for Capital Investments (Line 12). Cash Used for Capital Investments is Line 11.

Increase in Long-Term Debt (Line 14). Increase in Long-Term Debt reflects the new bonds issued by BPA to the U.S. Treasury to fund transmission and capital equipment programs. Also included in this amount may be any notes issued to the U.S. Treasury. Projected bonds are reduced to reflect $15 million of revenue financing per year. *See* Chapter 6, Documentation, TR-04-FS-BPA-01A.

Repayment of Long-Term Debt (Line 15). Repayment of Long-Term Debt is BPA's planned repayment of outstanding bonds issued by BPA to the U.S. Treasury as determined in the repayment studies. *See* Chapter 2, Documentation, TR-04-FS-BPA-01A.

Repayment of Capital Appropriations (Line 16). Repayment of Capital Appropriations represents projected amortization of outstanding BPA appropriations (pre self-financing) as determined in the repayment studies. *See* Chapter 2, Documentation, TR-04-FS-BPA-01A.

Cash From Treasury Borrowing and Appropriations (Line 17). Cash From Treasury Borrowing and Appropriations is the sum of Lines 14 through 16. This is the net cash flow resulting from increases in cash from new long-term debt and decreases in cash from repayment of long-term debt and capital appropriations.

Annual Increase (Decrease) in Cash (Line 18). Annual Increase (Decrease) in Cash, the sum of Lines 8, 12, and 17, reflects the annual net cash flow from current operations and investing and financing activities. Revenue requirements are set to meet all projected annual cash flow requirements, as included on the Statement of Cash Flows. A decrease shown in this line would indicate that annual revenues would be insufficient to cover the year's cash requirements. In such cases, Minimum Required Net Revenues are included to offset such decrease. *See* discussion above of Minimum Required Net Revenues (Line 2).

Planned Net Revenues For Risk (Line 19). Planned Net Revenues For Risk reflects the amounts included in revenue requirements to meet BPA's risk mitigation objectives (from Table 3, Line 17.)

Total Annual Increase (Decrease) in Cash (Line 20). Total Annual Increase (Decrease) in Cash, the sum of Lines 18 and 19, is the total annual cash that is projected to be available to add to BPA's cash reserves.

4.2 Current Revenue Test

Consistent with RA 6120.2, the continuing adequacy of existing rates must be tested annually. The current revenue test determines whether the revenues expected from current rates can continue to meet cost recovery requirements.

For the rate test period, the demonstration of the inadequacy of current rates is shown on Tables 5 and 6. Table 5 is a pro forma income statement for each year. Table 6, Statement of Cash Flows, tests the sufficiency of the resulting Net Revenues from Table 5 (Line 17) for making the planned annual amortization payments and achieving the Administrator's financial objectives. The Total Annual Increase (Decrease) in Cash (Table 6, Line 18) must be at least zero to demonstrate the adequacy of the projected revenues to cover all cash payment requirements. The current revenue test shows that current rates are substantially insufficient to satisfy cost recovery requirements in the rate period.

Table 7 shows the inadequacy of current rates to satisfy cost recovery requirements over the 35-year repayment period. The focal point of these tables is the Net Position (Column K), which is the amount of funds provided by revenues that remain after meeting annual expenses requiring cash for the rate period and repayment of the Federal investment. Thus, if the Net Position is zero or greater in each year of the rate approval period through the repayment period, the projected revenues demonstrate BPA's ability to repay the Federal investment in the FCRPS within the allowable time. As shown in Column K, the Net Position results are negative for each year of the rate approval period and in each year of the repayment period.

4.3 Revised Revenue Test

Consistent with RA 6120.2, the adequacy of proposed rates must be demonstrated. The revised revenue test determines whether the revenues projected from proposed rates will meet cost recovery requirements as well as the Treasury payment probability risk goal for the rate approval period. The revised revenue test was conducted using the forecast of revenues under proposed rates. The results of the revised revenue test demonstrate that proposed rates are adequate to fulfill the basic cost recovery requirements for the rate approval period of FYs 2004 and 2005.

For the rate test period, the demonstration of the adequacy of proposed rates is shown on Tables 8 and 9. Table 8 presents pro forma income statements for each year. Table 9, Statement of Cash Flows, tests the sufficiency of the resulting Net Revenues from Table 8 (Line 17) for making the planned annual amortization payments and achieving the Administrator's financial objectives. This is demonstrated by the Total Annual Increase (Decrease) in Cash (Line 18). The annual cash flow (Line 18) must be at least zero to demonstrate the adequacy of the projected revenues to cover all cash payment requirements. To accommodate the pattern of annual revenues and expenses, $1.5 million of planned amortization was shifted from FY 2004 to FY 2005.

4.4 Repayment Test at Proposed Rates

Table 10 demonstrates whether projected revenues from proposed rates are adequate to meet the cost recovery criteria of RA 6120.2 over the repayment period. The data are presented in a format consistent with the revised revenue tests (Tables 8 and 9) and separate accounting analyses. The focal point of these tables is the Net Position (Column K), which is the amount of funds provided by revenues that remain after meeting annual expenses requiring cash for the rate period and repayment of the Federal investment. Thus, if the Net Position is zero or greater in each year of the rate approval period through the repayment period, the projected revenues demonstrate BPA's ability to repay the Federal investment in the FCRPS within the allowable time. As shown in Column K, the resulting Net Position is greater than zero for each year of the rate approval period and in each year of the repayment period.

The historical data on this table have been taken from BPA's separate accounting analysis. The rate test period data have been developed specifically for this rate filing. The repayment period data are presented consistent with the requirements of RA 6120.2.

5. LEGAL REQUIREMENTS AND POLICIES

This chapter summarizes the statutory framework that guides the development of BPA's transmission revenue requirement and the recovery of BPA's transmission costs and expenses among the various users of the FCRTS, and the repayment policies that BPA follows in the development of its revenue requirement.

5.1 Development of BPA's Revenue Requirements

BPA's revenue requirements are governed by three main legislative acts: the Flood Control Act of 1944, P.L. No. 78-534, 58 Stat. 890, amended 1977; the Federal Columbia River Transmission System Act (Transmission System Act) of 1974, P.L. No. 93-454, 88 Stat. 1376; and the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), P.L. No. 96-501, 94 Stat. 2697. Other statutory provisions that guide the development of BPA's revenue requirements include the Federal Power Act, as amended by the Energy Policy Act of 1992 (EPA-92), P.L. No. 102-486. 106 Stat. 2776; and the Omnibus Consolidated Rescissions and Appropriations Act of 1996, P.L. No. 104-134, Stat. 132.

DOE Order "Power Marketing Administration Financial Reporting", RA 6120.2, issued by the Secretary of Energy provides guidance to Federal power marketing agencies regarding repayment of the Federal investment. In addition, policies issued by the FERC provide guidance on transmission pricing.

5.1.1 Legal Requirement Governing BPA's Revenue Requirement

BPA constructs, operates, and maintains the FCRTS within the Pacific Northwest and makes improvements or replacements thereto as are appropriate and required to: (a) integrate and transmit electric power from existing or additional Federal or non-Federal generating units; (b) provide service to BPA customers; (c) provide inter-regional transmission facilities; and (d) maintain the electrical stability and reliability of the Federal system. Section 4 of the Federal Columbia River Transmission System Act (Transmission System Act), 16 U.S.C. §838b. The transmission system is built to encourage the widest possible use of all electric energy. Section 5, Flood Control Act, 16 U.S.C. §825s.

BPA's rates must be set in a manner that ensures revenue levels sufficient to recover its costs. This requirement was first set forth in Section 7 of the Bonneville Project Act, 16 U.S.C. § 832f (as amended 1977) which provided that:

> *Rate schedules shall be drawn having regard to the recovery (upon the basis of the application of such rate schedules to the capacity of the electric facilities of the Bonneville project) of the cost of producing and transmitting such electric energy, including the amortization of the capital investment over a reasonable period of years.*

This cost recovery principle was repeated for Army reservoir projects in Section 5 of the Flood Control Act of 1944, 16 U.S.C. 825s (as amended 1977). In 1974, Section 9 of the Transmission System Act, 16 U.S.C, § 838g, expanded the cost recovery principle so that BPA's rates would be set to also recover:

> *payments provided [in the Administrator's annual budget], and (3) at levels to produce such additional revenues as may be required, in the aggregate with all other revenues of the Administrator, to pay when due the principal of, premiums, discounts, and expenses in connection with the issuance of and interest on all bonds issued and outstanding pursuant to [this Act,] and amounts required to establish and maintain reserve and other funds and accounts established in connection therewith.*

The Northwest Power Act reiterates and clarifies the cost recovery principle. Section 7(a)(1) of the Northwest Power Act, 16 U.S.C. § 839e(a)(1), provides that:

> *The Administrator shall establish, and periodically review and revise, rates for the sale and disposition of electric energy and capacity and for the transmission of non-Federal power. Such rates shall be established and, as appropriate, revised to recover, in accordance with sound business principles, the costs associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power System (including irrigation costs required to be repaid out of power revenues) over a reasonable period of years and the other costs and expenses incurred by the Administrator pursuant to this Act and other provisions of law. Such rates shall be established in accordance with Sections 9 and 10 of the Federal Columbia River Transmission System Act (16 U.S.C. § 838), Section 5 of the Flood Control Act of 1944, and the provisions of this Chapter.*

The Northwest Power Act also provides that FERC's confirmation and approval of BPA rates shall assure that the revenue requirement is adequate to recover BPA's costs and ensure timely U.S. Treasury repayments. Section 7(a)(2), 16 U.S.C. § 839e(a)(2), provides:

> *Rates established under this section shall become effective only, except in the case of interim rules as provided in subsection (i)(6), upon confirmation and approval by the Federal Energy Regulatory Commission upon a finding by the Commission, that such rates:*
>
> *(A) are sufficient to assure repayment of the Federal investment in the Federal Columbia River Power System over a reasonable number of years after first meeting the Administrator's other costs.*
>
> *(B) are based upon the Administrator's total system costs; and*
>
> *(C) insofar as transmission rates are concerned, equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system.*

More recently, Congress amended the Federal Power Act to allow FERC to order a transmitting utility, including BPA, to provide transmission services (including the enlargement of transmission capacity necessary to provide such services) to an applicant. Section 211(a) of the Federal Power Act, 16 U.S.C. § 824j(a). In applying the Federal Power Act provisions to FERC-ordered transmission service on the FCRTS, section 212(i), 16 U.S.C. § 824k(i)(1)(B), provides that FERC shall assure that

> *(i) the provisions of otherwise applicable Federal laws shall continue in full force and effect and shall continue to be applicable to the system; and*
>
> *(ii) the rates for the transmission of electric power on the system shall be governed only by such otherwise applicable provisions of law and not by any provision of section 824i of this title, 824j of this title, this section, and section 824l of this title, except that no rate for the transmission of power on the system shall be unjust, unreasonable, or unduly discriminatory or preferential , as determined by the Commission.*

Development of the revenue requirement is a critical component of meeting the statutory cost recovery principles. The costs associated with FCRTS and associated services and expenses, as well as other costs incurred by the Administrator in furtherance of BPA's mission, are included in the Study.

5.1.2 The BPA Appropriations Refinancing Act

As in the prior rate period, BPA's transmission rates for the FY 2004 - 2005 rate period will reflect the requirements of the Refinancing Act, part of the Omnibus Consolidated Rescissions and Appropriations Act of 1996, P.L. No. 104-134, 110 Stat. 1321, enacted in April 1996. The Refinancing Act required that unpaid principal on BPA appropriations ("old capital investments") at the end of FY 1996 be reset at the present value of the principal and annual interest payments BPA would make to the U.S. Treasury for these obligations absent the Refinancing Act, plus $100 million. 16 U.S.C. § 838l(b). The Refinancing Act also specified that the new principal amounts of the old capital investments be assigned new interest rates from the Treasury yield curve prevailing at the time of the refinancing transaction. 16 U.S.C. §838l(a)(6)(A).

The Refinancing Act restricts prepayment of the new principal for old capital investments to $100 million during the first five years after the effective date of the financing. 16 U.S.C. § 838l(e). The Refinancing Act also specifies that repayment periods on new principal amounts may not be earlier than determined prior to the refinancing. 16 U.S.C. §838l(d).

The Refinancing Act also directs the Administrator to offer to provide assurance in new or existing power, transmission, or related service contracts that the Government would not increase the repayment obligations in the future. 16 U.S.C. §838l(i).

5.2 Repayment Requirements and Policies

5.2.1 Separate Repayment Studies

Section 10 of the Transmission System Act, 16 U.S.C. §838h, and section 7(a)(2)(C) of the Northwest Power Act, 16 U.S.C. §839e(a)(2)(C), provide that the recovery of the costs of the Federal transmission system shall be equitably allocated between Federal and non-Federal power utilizing such system. In 1982, FERC first directed BPA to provide accounting and repayment statements for its transmission system separate and apart from the accounting and repayment statements for the Federal generation system. *See* 20 FERC ¶61,142 (1982). FERC required BPA to establish books of account for the FCRTS separate from its generation costs; explained that the FCRTS shall be comprised of all investments, including administrative and management costs, related to the transmission of electric power; and directed BPA to develop repayment studies for its transmission function separate from its generation function that set forth the date of each investment, the repayment date and the amount repaid from transmission revenues. *See* 26 FERC ¶ 61,096 (1984). FERC approved BPA's methodology for separate repayment studies in 1984. 28 FERC ¶61,325 (1984).

BPA has prepared separate repayment studies for its transmission and generation functions since 1984. BPA has therefore developed the transmission revenue requirement with no change in this repayment policy.

5.2.2 Repayment Schedules

The statutes applicable to BPA do not include specific directives for scheduling repayment of old capital appropriations and bonds issued to Treasury other than a directive that the Federal investment be amortized over a reasonable period of years. BPA's repayment policy has been established largely through administrative interpretation of its statutory requirements, with Congressional encouragement and occasional admonishment.

There have been a number of changes in BPA's repayment policy over the years concurrent with expansion of the Federal system and changing conditions. In general, current repayment criteria first were approved by the Secretary of the Interior on April 3, 1963. These criteria were refined and submitted to the Secretary and the Federal Power Commission (the predecessor agency to FERC) in support of BPA's rate filing in September 1965.

The repayment policy was presented to Congress for its consideration for the authorization of the Grand Coulee Dam Third Powerhouse in June 1966. The underlying theory of repayment was discussed in the House of Representatives' Report related to authorization of this project, H.R. Rep. No. 1409, 89th Cong., 2d Sess. 9-10 (1966). As stated in that report:

> *Accordingly, in a repayment study there is no annual schedule of capital repayment. The test of the sufficiency of revenues is whether the capital investment can be repaid within the overall repayment period established for each power project, each increment of investment in the transmission system, and each block of irrigation assistance. Hence, repayment may proceed at a faster or slower pace from year-to-year as conditions change.*

This approach to repayment scheduling has the effect of averaging the year-to-year variations in costs and revenues over the repayment period. This results in a uniform cost per unit of power sold, and permits the maintenance of stable rates for extended periods. It also facilitates the orderly marketing of power and permits BPA's customers, which include both electric utilities and electro-process industries, to plan for the future with assurance.

The Secretary of the Interior issued a statement of power policy on September 30, 1970, setting forth general principles that reaffirmed the repayment policy as previously developed. The most pertinent of these principles was set forth in the Department of the Interior Manual, Part 730, Chapter 1:

> A. *Hydroelectric power, although not a primary objective, will be proposed to Congress and supported for inclusion in multiple-purpose Federal projects when . . . it is capable of repaying its share of the Federal investment, including operation and maintenance costs and interest, in accordance with the law.*
>
> B. *Electric power generated at Federal projects will be marketed at the lowest rates consistent with sound financial management. Rates for the sale of Federal electric power will be reviewed periodically to assure their sufficiency to repay operating and maintenance costs and the capital investment within 50 years with interest that more accurately reflects the cost of money.*

To achieve a greater degree of uniformity in repayment policy for all Federal power marketing agencies, the Deputy Assistant Secretary of the Department of the Interior (DOI) issued a memo on August 2, 1972, outlining: (1) a uniform definition of the commencement of the repayment period for a particular project; (2) the method for including future replacement costs in repayment studies; and (3) a provision that the investment or obligation bearing the highest interest rate shall be amortized first, to the extent possible, while still complying with the prescribed repayment period established for each increment of investment.

A further clarification of the repayment policy was outlined in a joint memo of January 7, 1974, from the Assistant Secretary for Reclamation and Assistant Secretary for Energy and Minerals. This memo states that in addition to meeting the overall objective of repaying the Federal investment or obligations within the prescribed repayment periods, revenues shall be adequate, except in unusual circumstances, to repay annually all costs for O&M, purchased power, and interest.

On March 22, 1976, the Department of the Interior issued Chapter 4 of Part 730 of the DOI Manual to codify financial reporting requirements for the Federal power marketing agencies. Included therein are standard policies and procedures for preparing system repayment studies.

BPA and other Federal power marketing agencies were transferred to the newly established Department of Energy (DOE) on October 1, 1977. *See* DOE Organization Act, 42 U.S.C. § 7101 et seq. (1994). The DOE adopted the policies set forth in Part 730 of the DOI Manual by issuing Interim Management Directive No. 1701 on September 28, 1977, which subsequently was replaced by RA 6120.2 on September 20, 1979, as amended on October 1, 1983.

The repayment policy outlined in DOE Order RA 6120.2, paragraph 12, provides that BPA's total revenues from all sources must be sufficient to:

1. Pay all annual costs of operating and maintaining the Federal system;
2. Pay the cost each fiscal year of obtaining power through purchase and exchange agreements, the cost for transmission services, and other costs during the year in which such costs are incurred;

3. Pay interest expense each year on the unamortized portion of the Federal investment financed with appropriated funds at the interest rates established for each Federal generating project and for each annual increment of such investment in the BPA transmission system, except that recovery of annual interest expense may be deferred in unusual circumstances for short periods of time;
4. Pay when due the interest and amortization portion on outstanding bonds sold to the U.S. Treasury; and
5. Repay:
    a. each dollar of power investments and obligations in the Federal generating projects within 50 years after the projects become revenue producing, except as otherwise provided by law;
    b. each annual increment of Federal transmission investments and obligations within the average service life of such transmission facilities or within a maximum of 50 years, whichever is less; and
    c. the cost of each replacement of the Federal system within its service life up to a maximum of 50 years.

While RA 6120.2 allows repayment period of up to 50 years, BPA has set due dates at no more than 40 years to reflect expected service lives of new transmission investment. The Refinancing Act overrides provisions in RA 6120.2 related to determining interest during construction and assigning interest rates to Federal investments financed by appropriations. This Act also contains provisions on repayment periods (due dates) for the refinanced appropriations investments. The Refinancing Act is discussed in section 5.1.2 of this Study.

In addition, other sections within RA 6120.2 require that any outstanding deferred interest payments must be repaid before any planned amortization payments are made. Also, repayments are to be made by amortizing those Federal investments and obligations bearing the highest interest rate first, to the extent possible, while still completing repayment of each increment of Federal investment and obligation within its prescribed repayment period.

TABLES

Table 1

PROJECTED NET REVENUES FROM PROPOSED RATES
($000s)

Fiscal Year		Transmission
2004	Projected Revenues From Proposed Rates	$714,016
	Projected Expenses	$701,881
	Net Revenues	**$12,135**
2005	Projected Revenues From Proposed Rates	$735,142
	Projected Expenses	$729,213
	Net Revenues	**$5,929**
Average FYs 2004-2005	**Projected Revenues From Proposed Rates**	**$724,579**
	Projected Expenses	**$715,547**
	Net Revenues	**$9,032**

The TPP for the two year rate period is greater than 95%.

Table 2

PLANNED REPAYMENTS TO U.S. TREASURY
FYs 2004 – 2005 TRANSMISSION REPAYMENT STUDIES
($000s)

Fiscal Year	Annual Amortization
2004	$154,223
2005	$155,001
Total	$309,224

TABLE 3
TRANSMISSION REVENUE REQUIREMENT
INCOME STATEMENT
($thousands)

		A FY 2004	B FY 2005
1	OPERATING EXPENSES		
2	OPERATION AND MAINTENANCE	276,605	281,875
3	INTER-BUSINESS LINE EXPENSES	80,303	80,303
4	FEDERAL PROJECTS DEPRECIATION	178,813	190,746
5	TOTAL OPERATING EXPENSES	535,721	552,924
6	INTEREST EXPENSE		
7	INTEREST ON FEDERAL INVESTMENT -		
8	ON APPROPRIATED FUNDS	63,484	60,696
9	ON LONG-TERM DEBT	162,991	174,795
10	INTEREST INCOME	(20,380)	(20,400)
11	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	3,914	3,451
12	CAPITALIZATION ADJUSTMENT	(19,752)	(18,968)
13	AFUDC	(24,493)	(23,500)
14	NET INTEREST EXPENSE	165,764	176,074
15	TOTAL EXPENSES	701,485	728,998
16	MINIMUM REQUIRED NET REVENUES 1/	13,009	0
17	PLANNED NET REVENUES FOR RISK	0	0
18	TOTAL PLANNED NET REVENUES	13,009	0
19	**TOTAL REVENUE REQUIREMENT**	**714,494**	**728,998**

1/ SEE NOTE ON CASH FLOW TABLE.

TABLE 4
TRANSMISSION REVENUE REQUIREMENT
STATEMENT OF CASH FLOWS
($thousands)

		A FY 2004	B FY 2005
1	CASH FROM CURRENT OPERATIONS:		
2	MINIMUM REQUIRED NET REVENUES 1/	13,009	0
3	EXPENSES NOT REQUIRING CASH:		
4	FEDERAL PROJECTS DEPRECIATION	178,813	190,746
5	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	3,914	3,451
6	CAPITALIZATION ADJUSTMENT	(19,752)	(18,968)
7	ACCRUAL REVENUES (AC INTERTIE/FIBER)	(5,261)	(5,261)
8	CASH PROVIDED BY CURRENT OPERATIONS	170,723	169,968
9	CASH USED FOR CAPITAL INVESTMENTS:		
10	INVESTMENT IN:		
11	UTILITY PLANT	(335,035)	(284,706)
12	CASH USED FOR CAPITAL INVESTMENTS	(335,035)	(284,706)
13	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:		
14	INCREASE IN LONG-TERM DEBT	320,035	269,706
15	REPAYMENT OF LONG-TERM DEBT	(115,906)	(153,500)
16	REPAYMENT OF CAPITAL APPROPRIATIONS	(39,817)	(1)
17	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	164,312	116,205
18	ANNUAL INCREASE (DECREASE) IN CASH	0	1,467
19	PLANNED NET REVENUES FOR RISK	0	0
20	TOTAL ANNUAL INCREASE (DECREASE) IN CASH	0	1,467

1/ Line 18 must be greater than or equal to zero, otherwise net revenues will be added so that there are no negative cash flows for the year.

TABLE 5
CURRENT REVENUE TEST
INCOME STATEMENT
($thousands)

		A FY 2004	B FY 2005
1	REVENUES FROM CURRENT RATES	703,717	724,145
2	OPERATING EXPENSES		
3	OPERATION AND MAINTENANCE	276,605	281,875
4	INTER-BUSINESS LINE EXPENSES	80,303	80,303
5	FEDERAL PROJECTS DEPRECIATION	178,813	190,746
6	TOTAL OPERATING EXPENSES	535,721	552,924
7	INTEREST EXPENSE		
8	INTEREST ON FEDERAL INVESTMENT -		
9	ON APPROPRIATED FUNDS	63,484	60,696
10	ON LONG-TERM DEBT	162,991	174,795
11	INTEREST CREDIT ON CASH RESERVES	(19,473)	(18,457)
12	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	3,914	3,451
13	CAPITALIZATION ADJUSTMENT	(19,752)	(18,968)
14	AFUDC	(24,493)	(23,500)
15	NET INTEREST EXPENSE	166,671	178,017
16	TOTAL EXPENSES	702,392	730,941
17	NET REVENUES	1,325	(6,796)

TABLE 6
CURRENT REVENUE TEST
STATEMENT OF CASH FLOWS
($thousands)

		A FY 2005	B FY 2005
1	CASH FROM CURRENT OPERATIONS:		
2	NET REVENUES	1,325	(7,263)
3	EXPENSES NOT REQUIRING CASH:		
4	FEDERAL PROJECTS DEPRECIATION	178,813	190,746
5	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	3,914	3,451
6	CAPITALIZATION ADJUSTMENT	(19,752)	(18,968)
7	ACCRUAL REVENUES (AC INTERTIE/FIBER)	(5,261)	(5,261)
8	CASH PROVIDED BY CURRENT OPERATIONS	159,039	162,705
9	CASH USED FOR CAPITAL INVESTMENTS:		
10	INVESTMENT IN:		
11	UTILITY PLANT	(335,035)	(284,706)
12	CASH USED FOR CAPITAL INVESTMENTS	(335,035)	(284,706)
13	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:		
14	INCREASE IN LONG-TERM DEBT	320,035	269,706
15	REPAYMENT OF LONG-TERM DEBT	(115,906)	(153,500)
16	REPAYMENT OF CAPITAL APPROPRIATIONS	(39,817)	(1)
17	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	164,312	116,205
18	ANNUAL INCREASE (DECREASE) IN CASH	(11,684)	(5,796)

TABLE 7
FEDERAL COLUMBIA RIVER POWER SYSTEM
TRANSMISSION REVENUES FROM CURRENT RATES
REVENUE REQUIREMENT AND REPAYMENT STUDY RESULTS THROUGH THE REPAYMENT PERIOD
($000)

YEAR	A REVENUES (STATEMENT A)	B OPERATION & MAINTENANCE (STATEMENT E)	C PURCHASE AND EXCHANGE POWER (STATEMENT E)	D DEPRECIATION	E NET INTEREST (STATEMENT D)	F NET REVENUES (F=A-B-C-D-E)	G NONCASH EXPENSES 1/ (COLUMN D)	H FUNDS FROM OPERATION (H=F+G)	I AMORTIZATION (REV REQ STUDY DOC,V 2,C 3)	J IRRIGATION AMORTIZATION (STATEMENT C)	K NET POSITION (K=H-I-J)
COMBINED CUMULATIVE											
1977	3,298,951	963,839	348,748	807,047	1,220,170	(40,853)	807,047	766,194	628,460		137,734
TRANSMISSION											
1978	116,430	69,767		51,503	60,337	(65,177)	51,503	(13,674)	194		(13,868)
1979	107,017	73,801		53,756	69,112	(89,652)	53,756	(35,896)	26		(35,922)
1980	170,603	77,594		55,613	78,039	(40,643)	55,613	14,970	2		14,968
1981	202,740	87,243		59,638	87,665	(31,806)	59,638	27,832	1,236 2/		26,596
1982	269,200	91,562		64,458	106,190	6,990	64,458	71,448	0		71,448
1983	359,641	99,520		67,969	138,268	53,884	67,969	121,853	0		121,853
1984	417,821	101,406		60,360	158,783	97,272	60,360	157,632	26,722 3/		130,910
1985	510,030	141,623		71,012	160,336	137,059	71,012	208,071	199,646		8,425
1986	446,435	144,438		77,574	178,460	45,963	77,574	123,537	180,915		(57,378)
1987	456,728	148,596		85,807	177,020	45,305	85,807	131,112	148,860		(17,748)
1988	405,154	167,102		90,076	164,131	(16,155)	90,076	73,921	44,757		29,164
1989	422,202	175,240		93,076	164,044	(10,158)	93,076	82,918	119,322		(36,404)
1990	426,855	183,512		98,881	153,440	(8,978)	98,881	89,903	99,460		(9,557)
1991	439,871	199,668		98,731	139,458	2,014	98,731	100,745	70,930		29,815
1992	428,769	209,868		101,946	143,789	(26,834)	101,946	75,112	190,864		(115,752)
1993	417,555	189,926		101,929	173,271	(47,571)	101,929	54,358	130,989		(76,631)
1994	462,511	202,309		103,956	179,052	(22,806)	103,956	81,150	55,977		25,173
1995	490,264	200,501		112,940	181,744	(4,921)	112,940	264,019 /4	281,789		(17,770)
1996	534,456	206,128		125,961	165,175	37,192	123,219	145,411 /5	155,000		(9,589)
1997	503,217	197,202		124,457	176,977	4,581	109,802	114,383	125,000		(10,617)
1998	539,925	228,802		125,130	174,022	11,971	117,884	129,855	185,955		(56,100)
1999	552,134	231,410		147,176	173,574	(26)	133,779	133,753	139,784		(6,031)
2000	578,340	270,153		154,069	165,330	(11,212)	135,358	124,146	114,587		9,559
2001	646,673	282,851		154,881	165,404	43,537	151,746	195,283	59,064		136,219
2002	720,382	364,511		161,042	150,718	44,111	148,912	193,023	131,667		61,356
COST EVALUATION PERIOD											
2003	666,641	352,076		170,354	158,478	(14,267)	155,480	141,213	142,847		(1,634)
RATE APPROVAL PERIOD											
2004	703,717	356,908		178,813	166,671	1,325	157,714	144,039 /6	155,723		(11,684)
2005	724,145	362,178		190,746	178,484	(7,263)	169,968	147,705 /6	153,501		(5,796)

REPAYMENT PERIOD											
2006	724,145	362,178	(1,057)	190,746	181,346	(9,068)	169,968	160,900	151,249		9,651
2007	724,145	362,178	(1,118)	190,746	180,099	(7,760)	169,968	162,208	152,559		9,649
2008	724,145	362,178	(1,180)	190,746	178,188	(5,787)	169,968	164,181	154,532		9,649
2009	724,145	362,178	(1,240)	190,746	177,223	(4,762)	169,968	165,206	155,557		9,649
2010	724,145	362,178	(1,304)	190,746	175,902	(3,377)	169,968	166,591	156,942		9,649
2011	724,145	362,178	(1,368)	190,746	174,961	(2,372)	169,968	167,596	157,947		9,649
2012	724,145	362,178	(1,429)	190,746	174,625	(1,975)	169,968	167,993	158,344		9,649
2013	724,145	362,178	(1,490)	190,746	173,245	(534)	169,968	169,434	159,785		9,649
2014	724,145	362,178	(1,555)	190,746	171,996	780	169,968	170,748	161,099		9,649
2015	724,145	362,178	(1,620)	190,746	171,700	1,141	169,968	171,109	161,460		9,649
2016	724,145	362,178	(1,683)	190,746	173,388	(484)	169,968	169,484	159,835		9,649
2017	724,145	362,178	(1,749)	190,746	171,769	1,201	169,968	171,169	161,518		9,651
2018	724,145	362,178	(1,819)	190,746	179,861	(6,821)	169,968	163,147	153,498		9,649
2019	724,145	362,178	(1,893)	190,746	180,030	(6,916)	169,968	163,052	153,403		9,649
2020	724,145	362,178	(1,966)	190,746	180,931	(7,744)	169,968	162,224	152,575		9,649
2021	724,145	362,178	(2,043)	190,746	182,288	(9,024)	169,968	160,944	151,295		9,649
2022	724,145	362,178	(2,122)	190,746	184,018	(10,675)	169,968	159,293	149,644		9,649
2023	724,145	362,178	(2,197)	190,746	181,929	(8,511)	169,968	161,457	151,808		9,649
2024	724,145	362,178	(2,274)	190,746	189,315	(15,820)	169,968	154,148	144,499		9,649
2025	724,145	362,178	(2,348)	190,746	192,142	(18,573)	169,968	151,395	141,746		9,649
2026	724,145	362,178	(2,417)	190,746	195,335	(21,697)	169,968	148,271	138,622		9,649
2027	724,145	362,178	(2,479)	190,746	198,898	(25,198)	169,968	144,770	135,121		9,649
2028	724,145	362,178	(2,533)	190,746	198,544	(24,790)	169,968	145,178	135,529		9,649
2029	724,145	362,178	(2,577)	190,746	206,217	(32,419)	169,968	137,549	127,900		9,649
2030	724,145	362,178	(2,613)	190,746	212,772	(38,938)	169,968	131,030	121,381		9,649
2031	724,145	362,178	(2,635)	190,746	214,690	(40,834)	169,968	129,134	119,485		9,649
2032	724,145	362,178	(2,637)	190,746	219,735	(45,877)	169,968	124,091	114,442		9,649
2033	724,145	362,178	(2,633)	190,746	226,367	(52,513)	169,968	117,455	107,806		9,649
2034	724,145	362,178	(2,609)	190,746	233,159	(59,329)	169,968	110,639	100,986		9,653
2035	724,145	362,178	(2,574)	190,746	241,145	(67,350)	169,968	102,618	92,969		9,649
2036	724,145	362,178	(2,532)	190,746	248,790	(75,037)	169,968	94,931	85,282		9,649
2037	724,145	362,178	(2,481)	190,746	257,019	(83,317)	169,968	86,651	77,002		9,649
2038	724,145	362,178	(2,420)	190,746	265,863	(92,222)	169,968	77,746	68,089		9,657
2039	724,145	362,178	(2,363)	190,746	276,644	(103,060)	169,968	66,908	57,259		9,649
2040	724,145	362,178	(2,309)	190,746	286,670	(113,140)	169,968	56,828	47,179		9,649
TRANSMISSION TOTALS	38,064,531	18,092,125	(71,267)	9,657,964	11,244,774	(859,065)	8,801,967	8,053,902	5,430,525	0	520,736

1/CONSISTS OF DEPRECIATION PLUS ANY ACCOUNTING WRITE-OFFS INCLUDED IN EXPENSES.

2/CONSISTS OF AMORTIZATION ($1,650) AND DEFERRAL PAYMENT ($2,760).

3/CONSISTS OF AMORTIZATION ($1,342) AND DEFERRAL PAYMENT ($190,952).

4/INCREASED BY 156,000 AC INTERTIE CAPACITY OWNERSHIP PAYMENT.

5/REDUCED BY $15,000 OF REVENUE FINANCING.

6/REDUCED BY $15,000 OF REVENUE FINANCING.

TABLE 8
REVISED REVENUE TEST
INCOME STATEMENT
($thousands)

		A FY 2004	B FY 2005
1	REVENUES FROM PROPOSED RATES	714,016	735,142
2	OPERATING EXPENSES		
3	OPERATION AND MAINTENANCE	276,605	281,875
4	INTER-BUSINESS LINE EXPENSES	80,303	80,303
5	FEDERAL PROJECTS DEPRECIATION	178,813	190,746
6	TOTAL OPERATING EXPENSES	535,721	552,924
7	INTEREST EXPENSE		
8	INTEREST ON FEDERAL INVESTMENT -		
9	ON APPROPRIATED FUNDS	63,484	60,790
10	ON LONG-TERM DEBT	162,990	174,795
11	INTEREST CREDIT ON CASH RESERVES	(19,983)	(20,279)
12	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	3,914	3,451
13	CAPITALIZATION ADJUSTMENT	(19,752)	(18,968)
14	AFUDC	(24,493)	(23,500)
15	NET INTEREST EXPENSE	166,160	176,289
16	TOTAL EXPENSES	701,881	729,213
17	NET REVENUES	12,135	5,929

TABLE 9
REVISED REVENUE TEST
STATEMENT OF CASH FLOWS
($thousands)

		A FY 2004	B FY 2005
1	CASH FROM CURRENT OPERATIONS:		
2	NET REVENUES	12,135	5,929
3	EXPENSES NOT REQUIRING CASH:		
4	FEDERAL PROJECTS DEPRECIATION	178,813	190,746
5	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	3,914	3,451
6	CAPITALIZATION ADJUSTMENT	(19,752)	(18,968)
7	ACCRUAL REVENUES (AC INTERTIE/FIBER)	(5,261)	(5,261)
8	CASH PROVIDED BY CURRENT OPERATIONS	169,849	175,897
9	CASH USED FOR CAPITAL INVESTMENTS:		
10	INVESTMENT IN:		
11	UTILITY PLANT	(335,035)	(284,706)
12	CASH USED FOR CAPITAL INVESTMENTS	(335,035)	(284,706)
13	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:		
14	INCREASE IN LONG-TERM DEBT	320,035	269,706
15	REPAYMENT OF LONG-TERM DEBT	(115,906)	(153,500)
16	REPAYMENT OF CAPITAL APPROPRIATIONS	(38,317)	(1,501)
17	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	165,812	114,705
18	ANNUAL INCREASE (DECREASE) IN CASH	626	5,896

TABLE 10
FEDERAL COLUMBIA RIVER POWER SYSTEM
TRANSMISSION REVENUES FROM PROPOSED RATES
REVENUE REQUIREMENT AND REPAYMENT STUDY RESULTS THROUGH THE REPAYMENT PERIOD
($000)

	A	B	C	D	E	F	G	H	I	J	K
YEAR	REVENUES (STATEMENT A)	OPERATION & MAINTENANCE (STATEMENT E)	PURCHASE AND EXCHANGE POWER (STATEMENT E)	DEPRECIATION	NET INTEREST (STATEMENT D)	NET REVENUES (F=A-B-C-D-E)	NONCASH EXPENSES 1/ (COLUMN D)	FUNDS FROM OPERATION (H=F+G)	AMORTIZATION (REV REQ STUDY DOC,V 2,C 3)	IRRIGATION AMORTIZATION (STATEMENT C)	NET POSITION (K=H-I-J)
COMBINED CUMULATIVE											
1977	3,298,951	963,839	348,748	807,047	1,220,170	(40,853)	807,047	766,194	628,460		137,734
TRANSMISSION											
1978	116,430	69,767		51,503	60,337	(65,177)	51,503	(13,674)	194		(13,868)
1979	107,017	73,801		53,756	69,112	(89,652)	53,756	(35,896)	26		(35,922)
1980	170,603	77,594		55,613	78,039	(40,643)	55,613	14,970	2		14,968
1981	202,740	87,243		59,638	87,665	(31,806)	59,638	27,832	1,236 2/		26,596
1982	269,200	91,562		64,458	106,190	6,990	64,458	71,448	0		71,448
1983	359,641	99,520		67,969	138,268	53,884	67,969	121,853	0		121,853
1984	417,821	101,406		60,360	158,783	97,272	60,360	157,632	26,722 3/		130,910
1985	510,030	141,623		71,012	160,336	137,059	71,012	208,071	199,646		8,425
1986	446,435	144,438		77,574	178,460	45,963	77,574	123,537	180,915		(57,378)
1987	456,728	148,596		85,807	177,020	45,305	85,807	131,112	148,860		(17,748)
1988	405,154	167,102		90,076	164,131	(16,155)	90,076	73,921	44,757		29,164
1989	422,202	175,240		93,076	164,044	(10,158)	93,076	82,918	119,322		(36,404)
1990	426,855	183,512		98,881	153,440	(8,978)	98,881	89,903	99,460		(9,557)
1991	439,871	199,668		98,731	139,458	2,014	98,731	100,745	70,930		29,815
1992	428,769	209,868		101,946	143,789	(26,834)	101,946	75,112	190,864		(115,752)
1993	417,555	189,926		101,929	173,271	(47,571)	101,929	54,358	130,989		(76,631)
1994	462,511	202,309		103,956	179,052	(22,806)	103,956	81,150	55,977		25,173
1995	490,264	200,501		112,940	181,744	(4,921)	112,940	264,019 /4	281,789		(17,770)
1996	534,456	206,128		125,961	165,175	37,192	123,219	145,411 /5	155,000		(9,589)
1997	503,217	197,202		124,457	176,977	4,581	109,802	114,383	125,000		(10,617)
1998	539,925	228,802		125,130	174,022	11,971	117,884	129,855	185,955		(56,100)
1999	552,134	231,410		147,176	173,574	(26)	133,779	133,753	139,784		(6,031)
2000	578,340	270,153		154,069	165,330	(11,212)	135,358	124,146	114,587		9,559
2001	646,673	282,851		154,881	165,404	43,537	151,746	195,283	59,064		136,219
2002	720,382	364,511		161,042	150,718	44,111	148,912	193,023	131,667		61,356
COST EVALUATION PERIOD											
2003	666,641	352,076		170,354	158,478	(14,267)	155,480	141,213	142,847		(1,634)
RATE APPROVAL PERIOD											
2004	714,016	356,908		178,813	166,160	12,135	157,714	154,849 /6	154,223		626
2005	735,142	362,178		190,746	176,289	5,929	169,968	160,897 /6	155,001		5,896

REPAYMENT PERIOD											
2006	735,142	362,178	(1,057)	190,746	178,967	4,308	169,968	174,276	170,891		3,385
2007	735,142	362,178	(1,118)	190,746	176,303	7,033	169,968	177,001	173,616		3,385
2008	735,142	362,178	(1,180)	190,746	172,858	10,540	169,968	180,508	177,123		3,385
2009	735,142	362,178	(1,240)	190,746	170,246	13,212	169,968	183,180	179,795		3,385
2010	735,142	362,178	(1,304)	190,746	167,168	16,354	169,968	186,322	182,937		3,385
2011	735,142	362,178	(1,368)	190,746	164,341	19,245	169,968	189,213	185,828		3,385
2012	735,142	362,178	(1,429)	190,746	161,980	21,667	169,968	191,635	188,250		3,385
2013	735,142	362,178	(1,490)	190,746	158,442	25,266	169,968	195,234	191,849		3,385
2014	735,142	362,178	(1,555)	190,746	158,090	25,683	169,968	195,651	192,266		3,385
2015	735,142	362,178	(1,620)	190,746	161,635	22,203	169,968	192,171	188,786		3,385
2016	735,142	362,178	(1,683)	190,746	155,997	27,904	169,968	197,872	194,487		3,385
2017	735,142	362,178	(1,749)	190,746	147,377	36,590	169,968	206,558	203,171		3,387
2018	735,142	362,178	(1,819)	190,746	155,018	29,019	169,968	198,987	195,602		3,385
2019	735,142	362,178	(1,893)	190,746	152,757	31,354	169,968	201,322	197,937		3,385
2020	735,142	362,178	(1,966)	190,746	151,007	33,177	169,968	203,145	199,760		3,385
2021	735,142	362,178	(2,043)	190,746	149,572	34,689	169,968	204,657	201,272		3,385
2022	735,142	362,178	(2,122)	190,746	148,003	36,337	169,968	206,305	202,920		3,385
2023	735,142	362,178	(2,197)	190,746	141,367	43,048	169,968	213,016	209,631		3,385
2024	735,142	362,178	(2,274)	190,746	145,818	38,674	169,968	208,642	205,257		3,385
2025	735,142	362,178	(2,348)	190,746	144,530	40,036	169,968	210,004	206,619		3,385
2026	735,142	362,178	(2,417)	190,746	143,404	41,231	169,968	211,199	207,814		3,385
2027	735,142	362,178	(2,479)	190,746	142,303	42,394	169,968	212,362	208,977		3,385
2028	735,142	362,178	(2,533)	190,746	135,616	49,135	169,968	219,103	215,718		3,385
2029	735,142	362,178	(2,577)	190,746	138,495	46,300	169,968	216,268	212,883		3,385
2030	735,142	362,178	(2,613)	190,746	140,039	44,792	169,968	214,760	211,375		3,385
2031	735,142	362,178	(2,635)	190,746	139,150	45,703	169,968	215,671	212,286		3,385
2032	735,142	362,178	(2,637)	190,746	133,323	51,532	169,968	221,500	218,115		3,385
2033	735,142	362,178	(2,633)	190,746	131,797	53,054	169,968	223,022	219,637		3,385
2034	735,142	362,178	(2,609)	190,746	125,843	58,984	169,968	228,952	225,567		3,385
2035	735,142	362,178	(2,574)	190,746	134,270	50,522	169,968	220,490	217,105		3,385
2036	735,142	362,178	(2,532)	190,746	133,219	51,531	169,968	221,499	218,114		3,385
2037	735,142	362,178	(2,481)	190,746	126,534	58,165	169,968	228,133	224,748		3,385
2038	735,142	362,178	(2,420)	190,746	119,629	65,009	169,968	234,977	231,590		3,387
2039	735,142	362,178	(2,363)	190,746	128,008	56,573	169,968	226,541	223,156		3,385
2040	735,142	362,178	(2,309)	190,746	126,552	57,975	169,968	227,943	224,558		3,385
TRANSMISSION TOTALS	38,470,722	18,092,125	(71,267)	9,657,964	9,344,920	1,446,980	8,801,967	10,359,947	7,931,820	0	325,486

1/CONSISTS OF DEPRECIATION PLUS ANY ACCOUNTING WRITE-OFFS INCLUDED IN EXPENSES.

2/CONSISTS OF AMORTIZATION ($1,650) AND DEFERRAL PAYMENT ($2,760).

3/CONSISTS OF AMORTIZATION ($1,342) AND DEFERRAL PAYMENT ($190,952).

4/INCREASED BY 156,000 AC INTERTIE CAPACITY OWNERSHIP PAYMENT.

5/REDUCED BY $15,000 OF REVENUE FINANCING.

6/REDUCED BY $15,000 OF REVENUE FINANCING.

FIGURES

FIGURE 1

TRANSMISSION REVENUE REQUIREMENT PROCESS

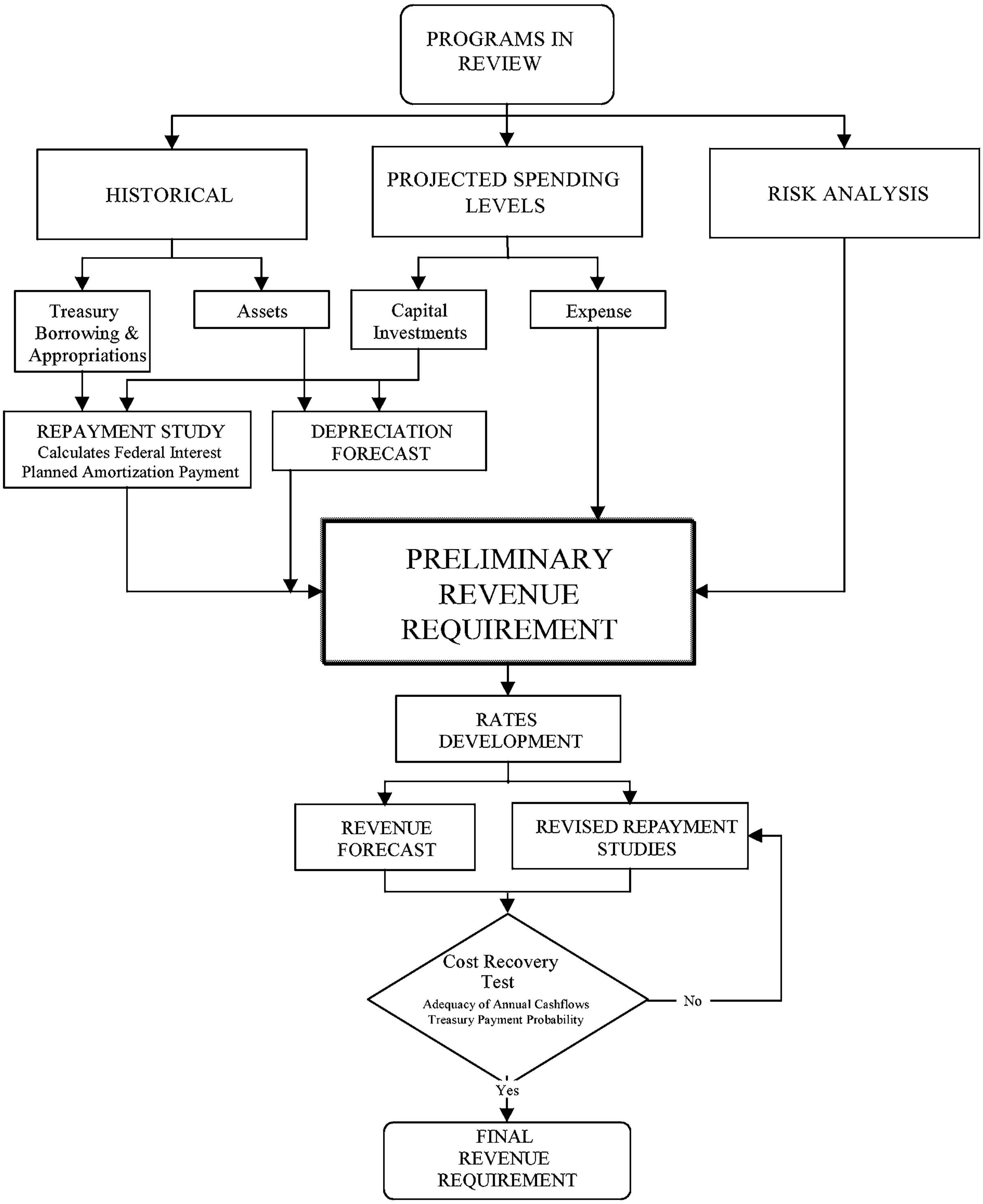
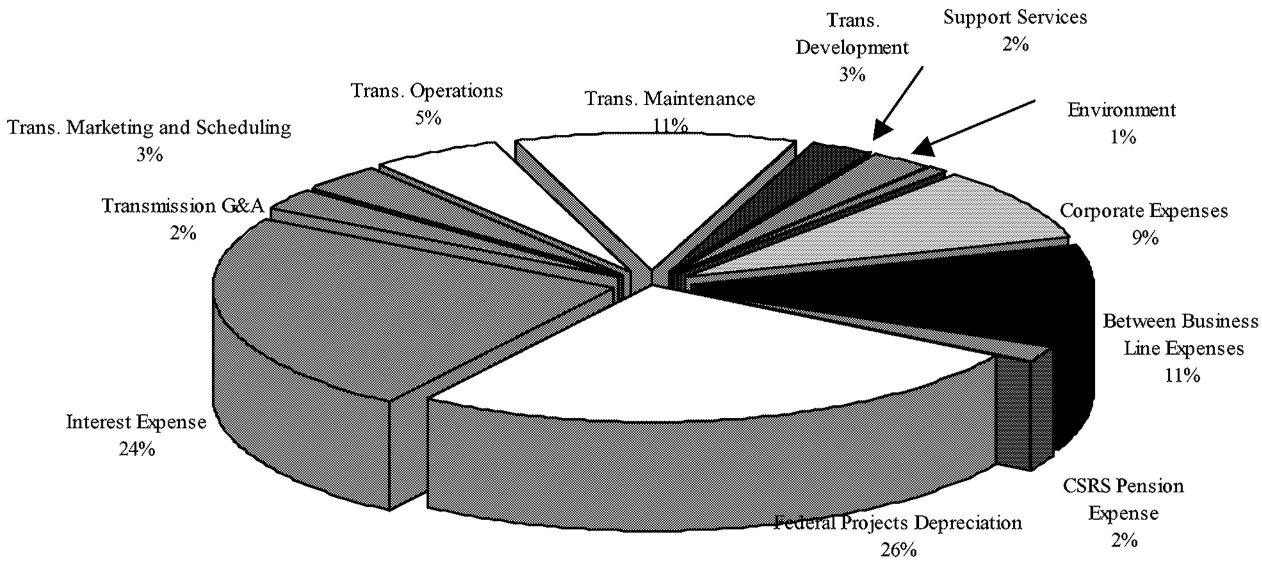


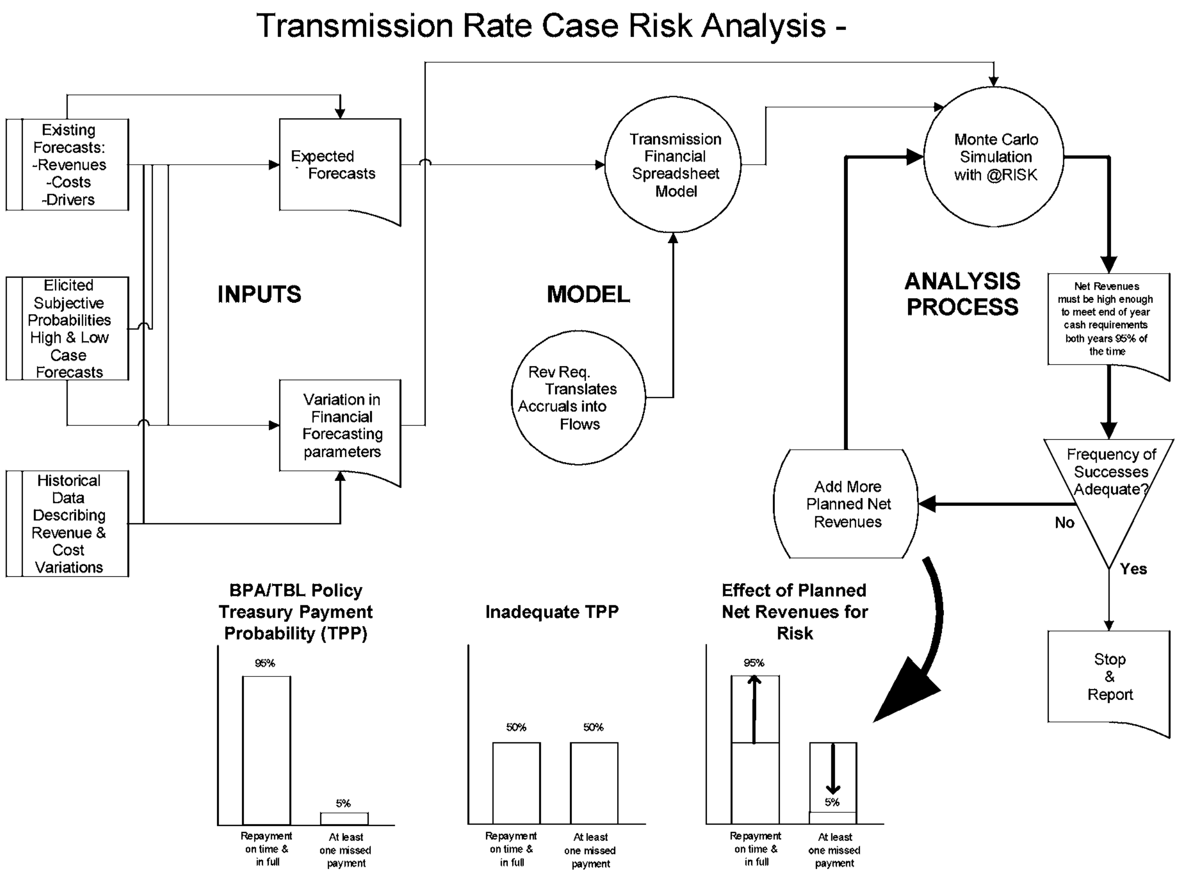
Figure 2

Composition of Transmission Operating & Interest Expenses FY 2004-2005 Average



	($ in millions)			
	FY 2004	FY 2005	Average	
Transmission G&A	$ 17.5	$ 17.9	$ 17.7	2%
Transmission Marketing and Scheduling	$ 23.7	$ 24.3	$ 24.0	3%
Transmission System Operations	$ 37.5	$ 38.4	$ 38.0	5%
Transmission System Maintenance	$ 80.0	$ 82.0	$ 81.0	11%
Transmission System Development	$ 18.9	$ 19.3	$ 19.1	3%
Support Services	$ 17.6	$ 18.1	$ 17.9	2%
Environment	$ 4.5	$ 4.6	$ 4.6	1%
Corporate Expenses	$ 61.5	$ 64.0	$ 62.8	9%
Between Business Line Expenses	$ 80.3	$ 80.3	$ 80.3	11%
CSRS Pension Expense	$ 15.5	$ 13.3	$ 14.4	2%
Federal Projects Depreciation	$ 178.8	$ 190.7	$ 184.8	26%
Interest Expense	$ 165.8	$ 176.5	$ 171.2	24%
Total Transmission Expenses	**$ 701.6**	**$ 729.4**	**$ 715.5**	**100%**

Figure 3


Transmission Rate Case Risk Analysis -
Existing Forecasts: -Revenues -Costs -Drivers
Elicited Subjective Probabilities High & Low Case Forecasts
Historical Data Describing Revenue & Cost Variations
Expected Forecasts
Variation in Financial Forecasting parameters
INPUTS
MODEL
Transmission Financial Spreadsheet Model
Rev Req. Translates Accruals into Flows
Monte Carlo Simulation with @RISK
ANALYSIS PROCESS
Net Revenues must be high enough to meet end of year cash requirements both years 95% of the time
Frequency of Successes Adequate?
No
Yes
Add More Planned Net Revenues
Stop & Report
BPA/TBL Policy Treasury Payment Probability (TPP)
95%
5%
Repayment on time & in full
At least one missed payment
Inadequate TPP
50%
50%
Repayment on time & in full
At least one missed payment
Effect of Planned Net Revenues for Risk
95%
5%
Repayment on time & in full
At least one missed payment

APPENDIX A

THE REPAYMENT PROGRAM

1. REPAYMENT PROGRAM OPERATION

1.1. Purpose

The major purpose of the repayment program is to determine, consistent with applicable Federal statutes and policy, whether a given set of annual revenues is sufficient to repay with interest the long-term capital obligations of the FCRTS. The program calculates amortization and interest when determining the minimum revenue level necessary to recover these obligations.

1.2. Computation of Revenues Available for Interest and Amortization

Given a set of revenues and expenses for each year, a set of annual revenues available for interest and amortization can be obtained by subtracting non-investment-related expenses such as O&M expense from revenues (equation 1 below). This revenue subset can then be used to make interest expense and amortization payments on FCRTS-related appropriations and bonds.

(1) revenues available for interest and amortization_i =

revenues_i - expenses_i, $i=1,2,...,n$,

where n is the total number of years in the study.

1.3 Computation of Revenues Available for Amortization Payments

For each year, the revenues available for interest and amortization, less interest expense, are used to make amortization payments on the transmission obligations (equation 2 below). The repayment program recognizes the unique nature of each of the Federal investments and associated obligations. The program uses data for all specific investments. The project name, amount of principal, interest rate, in-service date, due date, and the nature of the investment are described for each investment.

(2) revenues available for interest and amortization_i -

$$\text{interest expense}_i = \sum_{j=1}^{m} \text{amortization payment}_{ij}, \quad i=1,2,\ldots n,$$

where m is the total number of Federal investments.

1.4. Computation of Principal Payments Given Due Dates

The amortization payments on each investment must total the investment's principal on or before its due date (equation 3):

$$(3) \qquad \sum_{i=1}^{n} \text{payment}_{ij} \leq \text{principal}_j, \quad j=1,2,\ldots m.$$

1.5. Ordering of Payments According to Highest Interest First Constraint

The process described above yields one set of equations in which the payments are summed by year and another set of equations in which the payments are summed by investment. Taken together, however, these two sets of equations have no unique solution. RA 6120.2 provides that "[t]o the extent possible, while still complying with the repayment periods established for each increment of investment and unless otherwise indicated by legislation, amortization of the investment will be accompanied by application to the highest interest-bearing investment first."

A new equation can be obtained for each year by adding together equation 2 for that year and all earlier years. This equation sums all amortization payments made on any investment that comes due in those years. This equation can be simplified by substituting the principal of each such investment for the sum of the amortization payments on that investment as given by equation 3. The resulting equation (equation 4 below) indicates that for any year the sum of amortization payments on obligations that are not due by that year cannot exceed the sum of the revenues available for interest and amortization less the accumulated interest expense and the accumulated principal of all investments that are due in, or prior to, that year.

(4) $$\sum_{i=1}^{k} \text{revenues available for interest and amortization}_i$$

$$-\sum_{i=1}^{k} \text{interest expense}_i - \sum_{\text{due}} \text{principal}_j = \sum_{\substack{\text{not}\\ \text{due}}} \sum_{i=1}^{k} \text{payment}_{ij}, \qquad k=1,2,\ldots,n.$$

The term "due" refers to Federal obligations due to be repaid in or prior to the year k, and "not due" refers to Federal obligations not due to be repaid by the year k.

For each year in the repayment study, the right side of equation 4 represents the amount of the accumulated amortization payments on Federal obligations that are not due. The left side of the equation represents the accumulated revenues available for making these payments on the Federal obligations. These amortization payments first will be made on the highest interest bearing Federal obligations in compliance with RA 6120.2. If for some future year this amount is evaluated as being zero or negative, then this equation implies that amortization payments can be made only on highest interest bearing Federal obligations that come due on or before that year.

1.6. Iteration Towards A Solution

Equations 2 through 4 do not permit a direct solution. Although the revenues and the Federal obligation that are due are known for all years, an amortization payment made in the current year will affect interest expense in future years. That is, interest expense will no longer have to be paid on the portion of the Federal obligations that has been amortized. This problem is solved using an iterative approach.

The program initially assumes no future interest expense in evaluating the left side of the fourth set of equations. Consequently, the net revenues available for payments on Federal obligations that are not due, but bear the highest interest rates, will be excessive. As payments are determined for each successive year, and the interest expense of a given year is calculated, they are used in the fourth set of equations for all later years. The fourth set of equations is thus modified, and the revenues available for payments on "not due" highest interest rate bearing Federal obligations are reduced. Therefore, the amortization of a Federal obligation on its due date, in order to satisfy equation 3, may violate equation 2. Equation 2 may be violated when a negative balance occurs. A negative balance will result when revenues available for interest and amortization are less than interest expense plus any amortization payments that are due. As a result, a second iteration is necessary.

In the second iteration, the interest expense developed in the first iteration is used in the fourth set of equations for future years. Since amortization payments on "not due" highest interest rate bearing Federal obligations were excessive in the first iteration, the interest expense developed in the first iteration will be less than the true interest expense. These estimates, however, are more accurate than an estimate of zero interest expense and, as a result, the negative balances will be reduced.

If revenues are sufficient to recover a set of annual expenses and to repay with interest BPA's long-term Federal obligations, then the interest expenses of successive iterations will converge and the negative balances will be reduced to zero and thus yield a solution. Under these conditions all four equations will be satisfied.

If revenues are insufficient, then compliance with the fourth set of equations will force amortization payments on the highest interest obligations to be delayed. This will cause an increase in interest expense, leaving less revenue available to amortize high interest obligations. The interest expense from successive iterations will diverge, and the negative balances will start increasing. Under these conditions no solution is possible given available revenues.

BPA does not deliberately plan to defer annual expenses in the future. Therefore, if revenues are insufficient to cover annual expenses for any year of the repayment period, the program decides that no solution is possible at that revenue level.

2. DETERMINING A SUFFICIENT REVENUE LEVEL

As noted above, the repayment program also is used to determine a minimum revenue level sufficient to meet a given set of repayment obligations.

A set of trial revenues can be obtained by multiplying a set of given revenues by a factor. A factor is an assigned real number. If the set of trial revenues obtained with a factor is found to be insufficient, then all lower factors are known to produce insufficient revenues. If some other factor is found to produce sufficient revenues, then all higher factors are known to produce sufficient revenues. Therefore, only intermediate factors need to be tested.

Testing any intermediate factor establishes one of two propositions: (1) that either it and all lower intermediate factors are excluded; or (2) that it and all higher intermediate factors are included. In this manner, the set of intermediate factors is reduced. Through this repeated testing (referred to as the binary search technique), the set of intermediate factors is reduced to a size determined by a preset tolerance limit (the tolerance level of the current study is set at .005 percent of the given revenues).

The lowest factor that is determined to produce sufficient revenues in accordance with this testing procedure will produce the minimum revenue level, within the accuracy of the program, that meets all repayment obligations with interest subject to the conditions specified in RA 6120.2 and relevant legislation.

3. TREATMENT OF BONDS ISSUED TO U.S. TREASURY

BPA's current long-term bonds issued to the Treasury consist of term bonds and callable bonds. The term bonds cannot be prepaid. Their amortization and the revenues required for such bonds are therefore excluded from the above calculations. The remaining bonds are callable bonds and have provisions that allow for early redemption before the maturity date—five years after the date of the issuance on some older bonds and longer periods on some of the more recently issued bonds. In addition, a premium must be paid if a bond is repaid before its due date. The premium that must be paid decreases with the age of the bond. This premium affects the repayment process in two ways.

First, such premiums must be included with the payments of equation 2 and consequently affect the fourth set of equations. The premium that is paid on any Federal bond is considered to be due when the Federal bond is due. The premiums of one iteration are accumulated by due year and included in the fourth set of equations for the following iteration. When each premium is paid in the following iteration, it is used to modify the fourth set of equations and also is accumulated in case another iteration is necessary.

Second, the decrease in the premium that must be paid also affects the highest interest selection process. This effect is equivalent, in total, to a fixed premium and a reduced interest rate. This reduced effective interest rate enters into the comparison with other Federal investments and obligations to determine which should be repaid first.

4. INTEREST INCOME

BPA is authorized by applicable legislation and RA 6120.2 to calculate interest income as a credit to interest expense. An interest income credit is computed within the repayment program based on the average cash balance of funds required to be collected for payments to the Treasury in that year. The program assumes that the cash accumulates at a uniform rate throughout the year, except for the semi-annual interest paid on bonds issued to the Treasury. At the end of the year the cash balance together with the interest credit earned thereon is used for payment of interest expense, amortization of the Federal investment and payment of bond premiums.

5. FLOW CHARTS

The following three pages contain flow charts associated with the repayment study program. The first chart shows the binary search process. The second chart shows the test for sufficiency. The third chart shows the application of revenues.

Figure A1

REPAYMENT PROGRAM
(BINARY SEARCH)
CHART 1

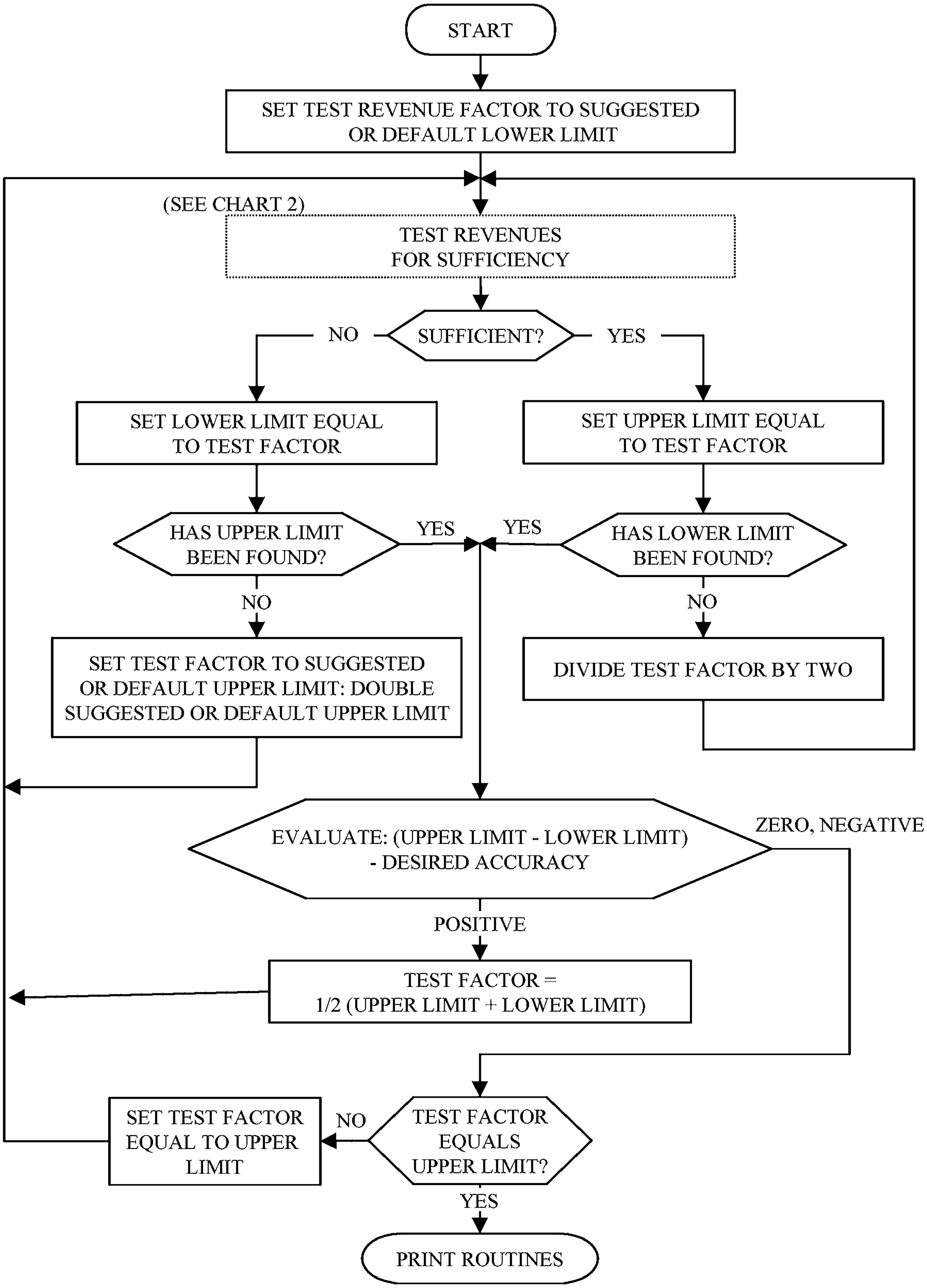


Figure A2

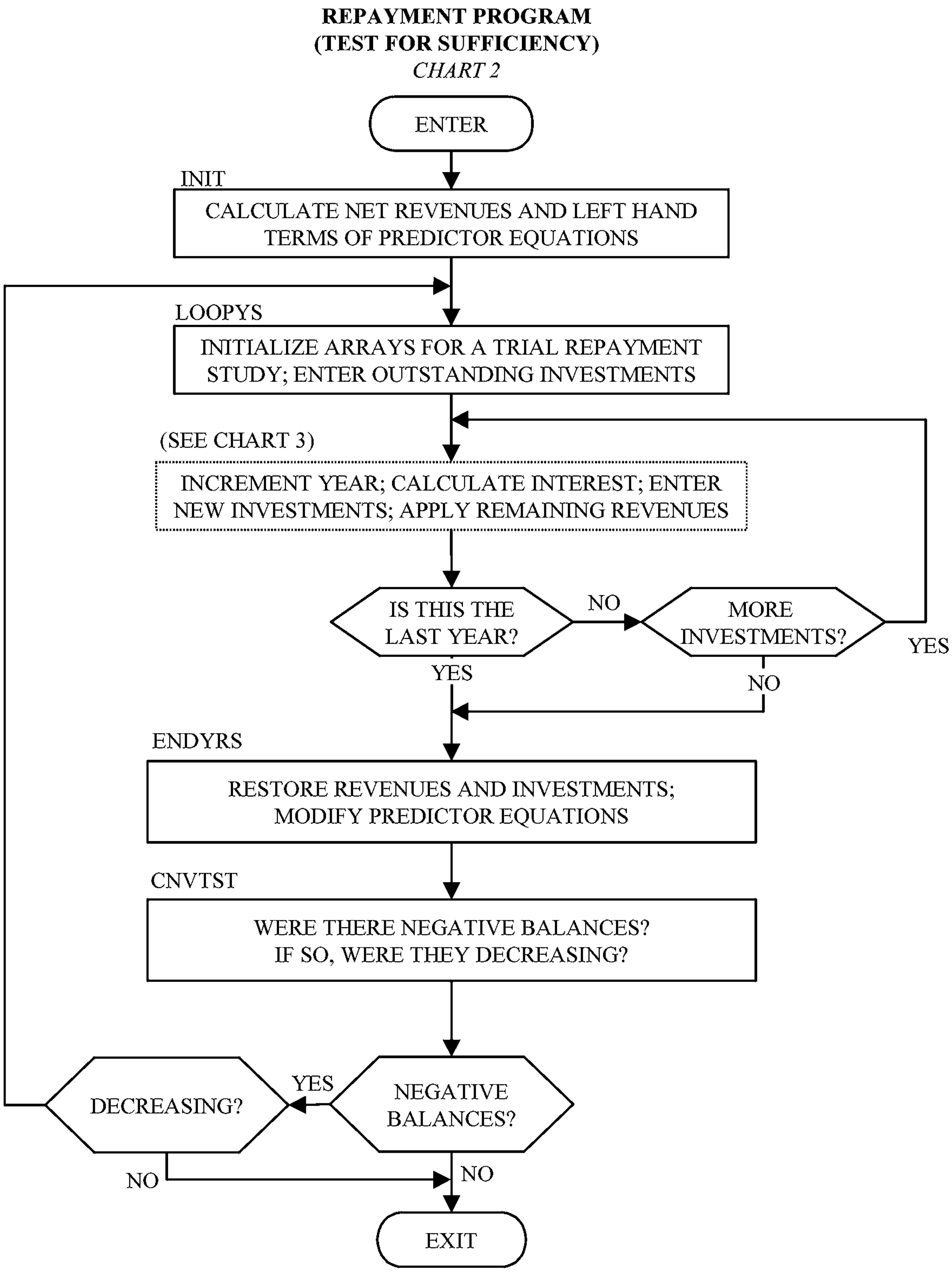
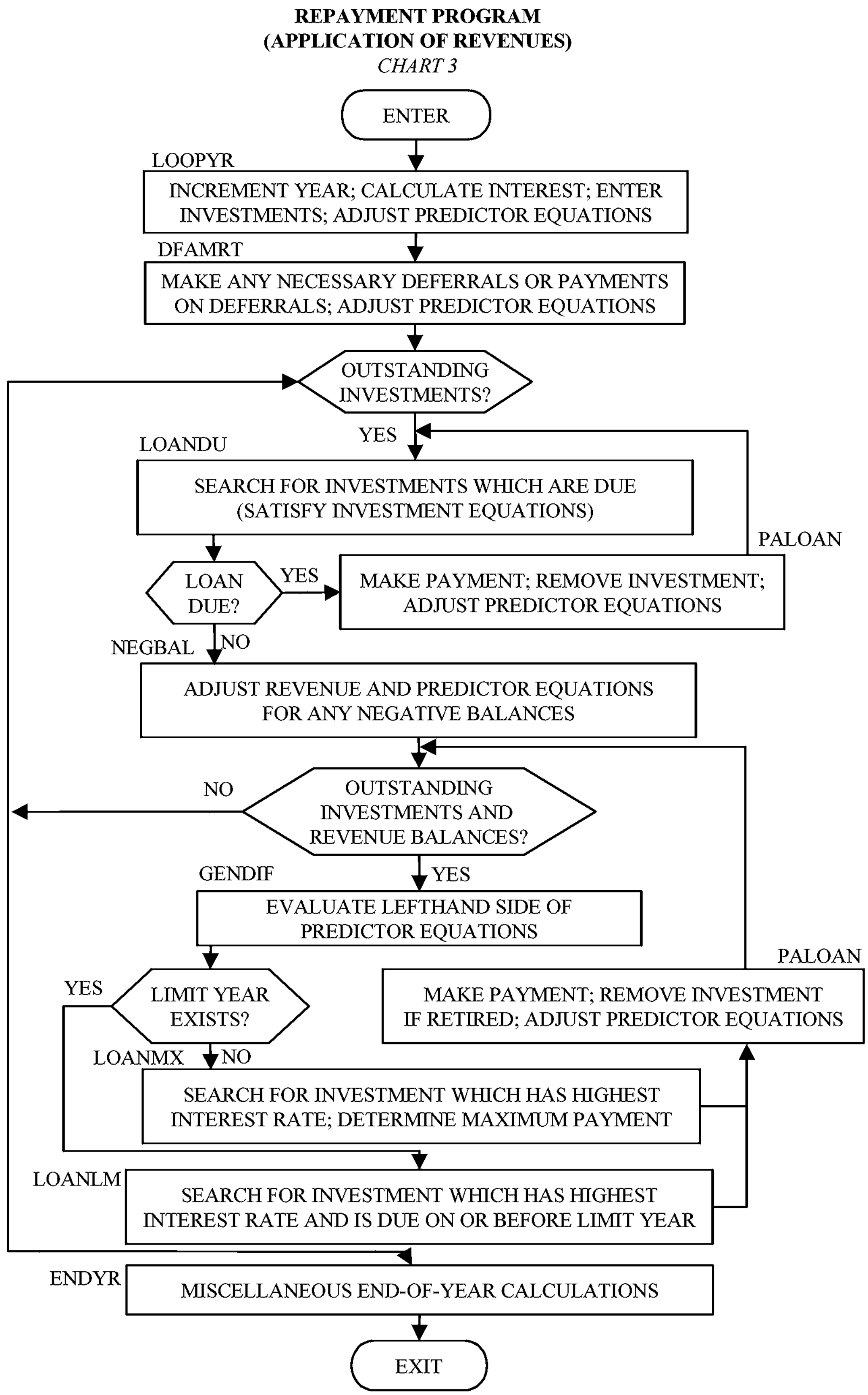

REPAYMENT PROGRAM
(TEST FOR SUFFICIENCY)
CHART 2
ENTER
INIT
CALCULATE NET REVENUES AND LEFT HAND TERMS OF PREDICTOR EQUATIONS
LOOPYS
INITIALIZE ARRAYS FOR A TRIAL REPAYMENT STUDY; ENTER OUTSTANDING INVESTMENTS
(SEE CHART 3)
INCREMENT YEAR; CALCULATE INTEREST; ENTER NEW INVESTMENTS; APPLY REMAINING REVENUES
IS THIS THE LAST YEAR?
NO
MORE INVESTMENTS?
YES
YES
NO
ENDYRS
RESTORE REVENUES AND INVESTMENTS; MODIFY PREDICTOR EQUATIONS
CNVTST
WERE THERE NEGATIVE BALANCES? IF SO, WERE THEY DECREASING?
DECREASING?
YES
NEGATIVE BALANCES?
NO
NO
EXIT

Figure A3


REPAYMENT PROGRAM
(APPLICATION OF REVENUES)
CHART 3
ENTER
LOOPYR
INCREMENT YEAR; CALCULATE INTEREST; ENTER INVESTMENTS; ADJUST PREDICTOR EQUATIONS
DFAMRT
MAKE ANY NECESSARY DEFERRALS OR PAYMENTS ON DEFERRALS; ADJUST PREDICTOR EQUATIONS
OUTSTANDING INVESTMENTS?
YES
LOANDU
SEARCH FOR INVESTMENTS WHICH ARE DUE (SATISFY INVESTMENT EQUATIONS)
PALOAN
LOAN DUE?
YES
MAKE PAYMENT; REMOVE INVESTMENT; ADJUST PREDICTOR EQUATIONS
NO
NEGBAL
ADJUST REVENUE AND PREDICTOR EQUATIONS FOR ANY NEGATIVE BALANCES
NO
OUTSTANDING INVESTMENTS AND REVENUE BALANCES?
GENDIF
YES
EVALUATE LEFTHAND SIDE OF PREDICTOR EQUATIONS
PALOAN
YES
LIMIT YEAR EXISTS?
MAKE PAYMENT; REMOVE INVESTMENT IF RETIRED; ADJUST PREDICTOR EQUATIONS
LOANMX
NO
SEARCH FOR INVESTMENT WHICH HAS HIGHEST INTEREST RATE; DETERMINE MAXIMUM PAYMENT
LOANLM
SEARCH FOR INVESTMENT WHICH HAS HIGHEST INTEREST RATE AND IS DUE ON OR BEFORE LIMIT YEAR
ENDYR
MISCELLANEOUS END-OF-YEAR CALCULATIONS
EXIT

6. DESCRIPTION OF REPAYMENT PROGRAM TABLES

Table A.1 shows the amortization results from the Transmission revised repayment studies for FYs 2004 and 2005, summarized by year for both due and discretionary bonds and appropriations.

Tables A.2, A through E, and Tables A.3, A through E, show the results of the Transmission repayment studies for FYs 2004 and 2005, respectively, using revenues from current rates. Table A.4 provides the application of amortization through the repayment period for transmission based upon the revenues forecast using revised rates.

Tables A.2A and A.3A display the repayment program results for transmission for FYs 2004 and 2005. The first column shows the applicable fiscal year. The second column shows the total investment costs of the transmission projects through the cost evaluation period. *See* Chapter 3 of the Documentation for the Revenue Requirement Study, TR-04-FS-BPA-01A. In the third column, forecasted replacements required to maintain the system are displayed through the repayment period. *See* Chapter 7 of Documentation for Revenue Requirement Study, TR-04-FS-BPA-01A. The fourth column shows the cumulative dollar amount of the transmission investment placed in service. This is comprised of historical plant-in-service, planned replacements and additions to plant through the cost evaluation period, and replacements from the end of the cost evaluation period to the end of the repayment study period. In these studies all additional plant is assumed to be financed by bonds.

The fifth column displays scheduled amortization payments for transmission for each year of the repayment period. Unamortized transmission obligations, shown in the last column, are determined by taking the previous year's unamortized amount, adding any replacements, and subtracting amortization.

Tables A.2B and A.3B display planned principal payments by fiscal year for Federal transmission obligations. Shown on these tables are the principal payments associated with appropriations and BPA bonds.

Tables A.2C and A.3C show the planned interest payments by fiscal year for Federal transmission obligations. Shown on these tables are the interest payments associated with appropriations and BPA bonds.

Tables A.2D and A.3D show a summary of the Federal transmission principal and interest payments through the repayment period.

Tables A.2E and A.3E compare the schedule of unamortized Federal transmission obligations resulting from the transmission repayment studies to those obligations that are due and must be paid for each year of the repayment period. The Unamortized Investment column shows remaining obligations for each year of the repayment period and is identical to the data shown in the last column of Tables A.2A and A.3A. The Term Schedule column shows obligations that are due for each year. It should be noted that unamortized obligations are always less than the term schedule, indicating that planned repayments are in excess of repayment obligations, thereby satisfying repayment requirements. (The total of Unamortized Investment need not be zero at the end of the repayment period because of the replacements occurring subsequent to the cost evaluation period.)

Table A.4 lists by year through the 35-year repayment period the application of the transmission amortization payments, consistent with the repayment studies, by project. The projected annual amortization payments on the transmission obligations are identified by the project name, in-service date, due date, and interest rate. The amount of the obligation is shown as both the original gross amount due and the net amount after all prior amortization payments.

TABLE A.1

TRANSMISSION AMORTIZATION
REVISED REPAYMENT STUDY FOR FINAL PROPOSAL 2004
FY 2004-2005
(000s)

Maturing/Due		
Bonds		
	2004	87,852
	2005	153,500
		241,352
Appropriations		
	2004	17,020
	2005	0
		17,020
TOTAL DUE		**258,372**

Scheduled But Not Yet Due		
Bonds		
	2004	28,054
	2005	0
		28,054
Appropriations		
	2004	21,297
	2005	1,501
		22,798
TOTAL SCHED / NOT DUE		**50,852**

Total by Year		
Bonds		
	2004	115,906
	2005	153,500
		269,406
Appropriations		
	2004	38,317
	2005	1,501
		39,818
TOTAL AMORTIZATION	2004	154,223
	2005	155,001
		309,224

TABLE A.2A

BONNEVILLE POWER ADMINISTRATION

TRANSMISSION REPAYMENT STUDY

OCTOBER 1, 2003 - SEPTEMBER 30, 2006 COST EVALUATION PERIOD

2004 RC FINAL PROPOSAL, $15m rf, 15-yr 02 bonds, CapReduc '03 3-17-03

Table B: Transmission Investments Placed in Service (1000s) (FY 2004)

	Investment Placed in Service					
Date	Initial Project	Replacements	Cumulative Amount in Service	Amortization	Discretionary Amortization	UnAmortized Investment
9/30/2002	5,853,996.00	1,066,763.00	6,920,759.00	-	-	6,920,759.00
9/30/2003	355,172.00	-	7,275,931.00	135,925.00	6,922.00	7,133,084.00
9/30/2004	324,002.00	-	7,599,933.00	104,872.00	50,851.01	7,301,362.99
9/30/2005	-	104,324.00	7,704,257.00	153,500.18	-	7,252,186.81
9/30/2006	-	109,171.00	7,813,428.00	155,739.00	851.33	7,204,767.48
9/30/2007	-	113,672.00	7,927,100.00	135,728.00	22,823.58	7,159,887.90
9/30/2008	-	117,822.00	8,044,922.00	123,032.00	38,220.07	7,116,457.83
9/30/2009	-	121,813.00	8,166,735.00	82,589.00	80,477.07	7,075,204.76
9/30/2010	-	125,815.00	8,292,550.00	116,260.00	49,041.15	7,035,718.61
9/30/2011	-	129,794.00	8,422,344.00	138,240.00	28,982.19	6,998,290.42
9/30/2012	-	133,879.00	8,556,223.00	81,305.00	87,298.39	6,963,566.03
9/30/2013	-	138,116.00	8,694,339.00	76,910.00	94,196.25	6,930,575.78
9/30/2014	-	142,455.00	8,836,794.00	124,413.00	49,142.96	6,899,474.82
9/30/2015	-	146,688.00	8,983,482.00	-	171,397.25	6,874,765.57
9/30/2016	-	150,821.00	9,134,303.00	-	172,783.68	6,852,802.89
9/30/2017	-	154,861.00	9,289,164.00	177,788.67	-	6,829,875.22
9/30/2018	-	158,673.00	9,447,837.00	2,675.00	167,874.04	6,817,999.18
9/30/2019	-	162,458.00	9,610,295.00	7,369.00	164,940.47	6,808,147.71
9/30/2020	-	166,193.00	9,776,488.00	-	171,902.76	6,802,437.95
9/30/2021	-	169,716.00	9,946,204.00	-	172,089.17	6,800,064.78
9/30/2022	-	173,017.00	10,119,221.00	-	172,062.45	6,801,019.33
9/30/2023	-	176,178.00	10,295,399.00	106,600.00	69,973.33	6,800,624.00
9/30/2024	-	179,147.00	10,474,546.00	-	170,782.98	6,808,988.02
9/30/2025	-	181,833.00	10,656,379.00	-	170,124.85	6,820,696.17
9/30/2026	-	184,264.00	10,840,643.00	-	169,251.13	6,835,709.04
9/30/2027	-	186,501.00	11,027,144.00	-	168,152.08	6,854,057.96
9/30/2028	-	188,553.00	11,215,697.00	112,300.00	59,518.13	6,870,792.83
9/30/2029	-	190,275.00	11,405,972.00	50,000.00	116,808.87	6,894,258.96
9/30/2030	-	191,790.00	11,597,762.00	-	162,886.55	6,923,162.41
9/30/2031	-	193,015.00	11,790,777.00	-	160,890.81	6,955,286.60
9/30/2032	-	194,027.00	11,984,804.00	98,900.00	64,027.20	6,986,386.40
9/30/2033	-	194,787.00	12,179,591.00	110,000.00	51,039.27	7,020,134.13
9/30/2034	-	195,105.00	12,374,696.00	158,400.00	2,187.21	7,054,651.92
9/30/2035	-	195,278.00	12,569,974.00	-	151,825.05	7,098,104.87
9/30/2036	-	195,354.00	12,765,328.00	-	150,675.64	7,142,783.23
9/30/2037	-	195,173.00	12,960,501.00	-	151,231.68	7,186,724.55
9/30/2038	-	194,865.00	13,155,366.00	148,343.90	-	7,233,245.65
9/30/2039	-	194,573.00	13,349,939.00	-	140,100.09	7,287,718.56
9/30/2040	-	-	13,349,939.00	-	140,728.13	7,146,990.43
9/30/2041	-	-	13,349,939.00	-	150,455.59	6,996,534.84
Total	6,533,170.00	6,816,769.00	-	2,400,889.75	3,952,514.41	-

File = TransRC2004-Final.sf-Trans 04RC-Final w/$15 RF,Mid-term Const,CapRed'03- SINGLE PURPOSE

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TABLE A.2B

BONNEVILLE POWER ADMINISTRATION

TRANSMISSION REPAYMENT STUDY

OCTOBER 1, 2003 - SEPTEMBER 30, 2006 COST EVALUATION PERIOD

2004 RC FINAL PROPOSAL, $15m rf, 15-yr 02 bonds, CapReduc '03 3-17-03

Table C: Principal Payments (FY 2004)

Date	Transmission Bonds	Transmission Appropriations
9/30/2003	116,600.00	26,247.00
9/30/2004	115,906.00	39,817.01
9/30/2005	153,500.00	0.18
9/30/2006	140,000.00	16,590.33
9/30/2007	111,254.00	47,297.58
9/30/2008	112,119.00	49,133.07
9/30/2009	72,700.00	90,366.07
9/30/2010	89,933.00	75,368.15
9/30/2011	115,000.00	52,222.19
9/30/2012	40,000.00	128,603.39
9/30/2013	-	171,106.25
9/30/2014	59,050.00	114,505.96
9/30/2015	76,183.43	95,213.82
9/30/2016	172,783.68	-
9/30/2017	177,788.67	-
9/30/2018	170,549.04	-
9/30/2019	172,309.47	-
9/30/2020	171,902.76	-
9/30/2021	172,089.17	-
9/30/2022	172,062.45	-
9/30/2023	176,573.33	-
9/30/2024	170,782.98	-
9/30/2025	170,124.85	-
9/30/2026	169,251.13	-
9/30/2027	168,152.08	-
9/30/2028	171,818.13	-
9/30/2029	166,808.87	-
9/30/2030	162,886.55	-
9/30/2031	160,890.81	-
9/30/2032	162,927.20	-
9/30/2033	161,039.27	-
9/30/2034	160,587.21	-
9/30/2035	151,825.05	-
9/30/2036	150,675.64	-
9/30/2037	151,231.68	-
9/30/2038	148,343.90	-
9/30/2039	140,100.09	-
9/30/2040	140,728.13	-
9/30/2041	150,455.59	-
Total	5,446,933.16	906,471.00

TABLE A.2C

BONNEVILLE POWER ADMINISTRATION

TRANSMISSION REPAYMENT STUDY

OCTOBER 1, 2003 - SEPTEMBER 30, 2006 COST EVALUATION PERIOD

2004 RC FINAL PROPOSAL, $15m rf, 15-yr 02 bonds, CapReduc '03 3-17-03

Table D: Interest Payments (FY 2004)

Date	Transmission Bonds	Transmission Appropriations
9/30/2003	136,862.00	65,279.28
9/30/2004	154,099.00	63,483.99
9/30/2005	160,099.98	60,680.83
9/30/2006	157,068.85	60,680.82
9/30/2007	156,324.53	59,524.89
9/30/2008	157,057.16	56,152.77
9/30/2009	158,854.49	52,600.44
9/30/2010	163,243.32	46,039.53
9/30/2011	166,821.34	40,603.47
9/30/2012	169,264.17	36,839.44
9/30/2013	176,126.34	27,535.41
9/30/2014	186,115.27	15,159.77
9/30/2015	196,624.40	6,874.35
9/30/2016	202,174.32	-
9/30/2017	197,232.32	-
9/30/2018	204,543.96	-
9/30/2019	202,855.53	-
9/30/2020	203,335.24	-
9/30/2021	203,223.83	-
9/30/2022	203,329.55	-
9/30/2023	198,891.67	-
9/30/2024	204,759.02	-
9/30/2025	205,491.15	-
9/30/2026	206,432.87	-
9/30/2027	207,593.92	-
9/30/2028	203,981.87	-
9/30/2029	209,035.13	-
9/30/2030	212,994.45	-
9/30/2031	215,012.19	-
9/30/2032	212,979.80	-
9/30/2033	214,865.73	-
9/30/2034	215,295.79	-
9/30/2035	224,024.95	-
9/30/2036	225,134.36	-
9/30/2037	224,531.31	-
9/30/2038	227,357.10	-
9/30/2039	235,549.91	-
9/30/2040	232,577.87	-
9/30/2041	222,850.41	-
Total	7,654,615.10	591,454.99

File = TransRC2004-Final.sf-Trans 04RC-Final w/$15 RF,Mid-term Const,CapRed'03- SINGLE PURPOSE

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TABLE A.2D

BONNEVILLE POWER ADMINISTRATION

TRANSMISSION REPAYMENT STUDY

OCTOBER 1, 2003 - SEPTEMBER 30, 2006 COST EVALUATION PERIOD

2004 RC FINAL PROPOSAL, $15m rf, 15-yr 02 bonds, CapReduc '03 3-17-03

Table G: Summary of Payments (FY 2004)

		Interest
Date	Transmission Principal Payment	Transmission Interest Payment
9/30/2003	142,847.00	202,141.28
9/30/2004	155,723.01	217,582.99
9/30/2005	153,500.18	220,780.81
9/30/2006	156,590.33	217,749.67
9/30/2007	158,551.58	215,849.42
9/30/2008	161,252.07	213,209.93
9/30/2009	163,066.07	211,454.93
9/30/2010	165,301.15	209,282.85
9/30/2011	167,222.19	207,424.81
9/30/2012	168,603.39	206,103.61
9/30/2013	171,106.25	203,661.75
9/30/2014	173,555.96	201,275.04
9/30/2015	171,397.25	203,498.75
9/30/2016	172,783.68	202,174.32
9/30/2017	177,788.67	197,232.32
9/30/2018	170,549.04	204,543.96
9/30/2019	172,309.47	202,855.53
9/30/2020	171,902.76	203,335.24
9/30/2021	172,089.17	203,223.83
9/30/2022	172,062.45	203,329.55
9/30/2023	176,573.33	198,891.67
9/30/2024	170,782.98	204,759.02
9/30/2025	170,124.85	205,491.15
9/30/2026	169,251.13	206,432.87
9/30/2027	168,152.08	207,593.92
9/30/2028	171,818.13	203,981.87
9/30/2029	166,808.87	209,035.13
9/30/2030	162,886.55	212,994.45
9/30/2031	160,890.81	215,012.19
9/30/2032	162,927.20	212,979.80
9/30/2033	161,039.27	214,865.73
9/30/2034	160,587.21	215,295.79
9/30/2035	151,825.05	224,024.95
9/30/2036	150,675.64	225,134.36
9/30/2037	151,231.68	224,531.31
9/30/2038	148,343.90	227,357.10
9/30/2039	140,100.09	235,549.91
9/30/2040	140,728.13	232,577.87
9/30/2041	150,455.59	222,850.41
Total	6,353,404.16	8,246,070.09

TABLE A.2E

BONNEVILLE POWER ADMINISTRATION
TRANSMISSION REPAYMENT STUDY
OCTOBER 1, 2003 - SEPTEMBER 30, 2006 COST EVALUATION PERIOD
2004 RC FINAL PROPOSAL, $15m rf, 15-yr 02 bonds, CapReduc '03 3-17-03

Table H: Summary of Investments Placed in Service (1000s) (FY 2004)

	Generation		Transmission	
Date	Unamortized Investment	Term Schedule	Unamortized Investment	Term Schedule
9/30/2002	-	-	3,138,294.68	5,688,062.00
9/30/2003	-	-	3,199,068.00	5,907,309.00
9/30/2004	-	-	3,367,346.99	6,126,439.00
9/30/2005	-	-	3,318,170.81	6,069,447.00
9/30/2006	-	-	3,270,751.48	6,022,879.00
9/30/2007	-	-	3,225,871.90	5,893,123.00
9/30/2008	-	-	3,182,441.83	5,887,913.00
9/30/2009	-	-	3,141,188.76	5,927,137.00
9/30/2010	-	-	3,101,702.61	5,936,692.00
9/30/2011	-	-	3,064,274.42	5,928,246.00
9/30/2012	-	-	3,095,487.65	5,980,820.00
9/30/2013	-	-	3,128,477.90	5,992,026.00
9/30/2014	-	-	3,159,578.86	5,885,068.00
9/30/2015	-	-	3,184,288.11	5,816,369.00
9/30/2016	-	-	3,206,250.79	5,732,543.00
9/30/2017	-	-	3,229,178.46	5,232,045.00
9/30/2018	-	-	3,241,054.50	5,147,040.00
9/30/2019	-	-	3,250,905.97	5,144,677.00
9/30/2020	-	-	3,256,615.73	5,228,028.00
9/30/2021	-	-	3,258,988.90	5,334,507.00
9/30/2022	-	-	3,258,034.35	5,459,513.00
9/30/2023	-	-	3,258,429.68	5,529,091.00
9/30/2024	-	-	3,250,065.66	5,708,238.00
9/30/2025	-	-	3,238,357.51	5,775,138.00
9/30/2026	-	-	3,223,344.64	5,959,402.00
9/30/2027	-	-	3,204,995.72	6,145,903.00
9/30/2028	-	-	3,188,260.85	6,222,156.00
9/30/2029	-	-	3,164,794.72	6,346,709.00
9/30/2030	-	-	3,135,891.27	6,404,221.00
9/30/2031	-	-	3,103,767.08	6,297,236.00
9/30/2032	-	-	3,072,667.28	5,942,363.00
9/30/2033	-	-	3,086,118.13	5,507,188.00
9/30/2034	-	-	3,120,635.92	5,443,893.00
9/30/2035	-	-	3,164,088.87	5,639,171.00
9/30/2036	-	-	3,208,767.23	5,834,525.00
9/30/2037	-	-	3,252,708.55	6,029,698.00
9/30/2038	-	-	3,299,229.65	5,872,066.00
9/30/2039	-	-	3,353,702.56	5,750,006.00
9/30/2040	-	-	3,212,974.43	5,645,682.00
9/30/2041	-	-	3,062,518.84	5,536,511.00
Total	-	-	127,879,291.29	231,929,080.00

Ferrand Jordan & Company *File = TransRC2004-Final.sf-Trans 04RC-Final w/$15 RF,Mid-term Const,CapRed'03- SINGLE PURPOSE*
Public Finance *3/24/2003 1:32 PM*

TABLE A.3A

BONNEVILLE POWER ADMINISTRATION

TRANSMISSION REPAYMENT STUDY

OCTOBER 1, 2003 - SEPTEMBER 30, 2006 COST EVALUATION PERIOD

2004 RC FINAL PROPOSAL, $15m rf, 15-yr 02 bonds, CapReduc '03 3-17-03

Table B: Transmission Investments Placed in Service (1000s) (FY 2005)

	Investment Placed in Service					
Date	Initial Project	Replacements	Cumulative Amount in Service	Amortization	Discretionary Amortization	UnAmortized Investment
9/30/2002	5,853,996.00	1,066,763.00	6,920,759.00	-	-	6,920,759.00
9/30/2003	355,172.00	-	7,275,931.00	135,925.00	6,922.00	7,133,084.00
9/30/2004	324,002.00	-	7,599,933.00	104,872.00	50,851.01	7,301,362.99
9/30/2005	273,245.00	-	7,873,178.00	153,500.93	-	7,421,107.06
9/30/2006	-	111,674.00	7,984,852.00	151,249.03	-	7,381,532.03
9/30/2007	-	116,348.00	8,101,200.00	135,728.00	16,830.92	7,345,321.11
9/30/2008	-	120,579.00	8,221,779.00	123,032.00	31,499.54	7,311,368.57
9/30/2009	-	124,617.00	8,346,396.00	82,589.00	72,967.60	7,280,428.97
9/30/2010	-	128,630.00	8,475,026.00	116,260.00	40,682.34	7,252,116.63
9/30/2011	-	132,612.00	8,607,638.00	138,240.00	19,707.31	7,226,781.32
9/30/2012	-	136,699.00	8,744,337.00	81,305.00	77,039.37	7,205,135.95
9/30/2013	-	140,962.00	8,885,299.00	76,910.00	82,874.82	7,186,313.13
9/30/2014	-	145,372.00	9,030,671.00	124,413.00	36,686.13	7,170,586.00
9/30/2015	-	149,712.00	9,180,383.00	-	161,460.01	7,158,837.99
9/30/2016	-	153,948.00	9,334,331.00	-	159,835.22	7,152,950.77
9/30/2017	-	158,066.00	9,492,397.00	161,517.60	-	7,149,499.17
9/30/2018	-	161,972.00	9,654,369.00	2,675.00	150,823.43	7,157,972.74
9/30/2019	-	165,862.00	9,820,231.00	7,369.00	146,034.14	7,170,431.60
9/30/2020	-	169,724.00	9,989,955.00	5,414.00	147,160.54	7,187,581.06
9/30/2021	-	173,415.00	10,163,370.00	-	151,294.79	7,209,701.27
9/30/2022	-	176,899.00	10,340,269.00	-	149,644.19	7,236,956.08
9/30/2023	-	180,232.00	10,520,501.00	106,600.00	45,207.88	7,265,380.20
9/30/2024	-	183,355.00	10,703,856.00	-	144,499.45	7,304,235.75
9/30/2025	-	186,194.00	10,890,050.00	-	141,745.66	7,348,684.09
9/30/2026	-	188,754.00	11,078,804.00	-	138,622.41	7,398,815.68
9/30/2027	-	191,075.00	11,269,879.00	-	135,120.76	7,454,769.92
9/30/2028	-	193,239.00	11,463,118.00	112,300.00	23,228.93	7,512,479.99
9/30/2029	-	195,064.00	11,658,182.00	50,000.00	77,899.58	7,579,644.41
9/30/2030	-	196,662.00	11,854,844.00	-	121,381.06	7,654,925.35
9/30/2031	-	197,985.00	12,052,829.00	-	119,485.17	7,733,425.18
9/30/2032	-	199,123.00	12,251,952.00	98,900.00	15,541.71	7,818,106.47
9/30/2033	-	200,016.00	12,451,968.00	49,479.35	58,326.53	7,910,316.59
9/30/2034	-	200,455.00	12,652,423.00	100,073.47	912.79	8,009,785.33
9/30/2035	-	200,770.00	12,853,193.00	-	92,969.37	8,117,585.96
9/30/2036	-	200,989.00	13,054,182.00	-	85,282.48	8,233,292.48
9/30/2037	-	200,973.00	13,255,155.00	-	77,002.47	8,357,263.01
9/30/2038	-	200,789.00	13,455,944.00	68,089.00	-	8,489,963.01
9/30/2039	-	200,601.00	13,656,545.00	-	57,259.26	8,633,304.75
9/30/2040	-	200,477.00	13,857,022.00	-	47,179.36	8,786,602.39
9/30/2041	-	-	13,857,022.00	-	41,089.60	8,745,512.79
Total	6,806,415.00	7,050,607.00	-	2,186,441.38	2,925,067.83	-

File = TransRC2004-Final.sf-Trans 04RC-Final w/$15 RF,Mid-term Const,CapRed'03- SINGLE PURPOSE

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TABLE A.3B

BONNEVILLE POWER ADMINISTRATION

TRANSMISSION REPAYMENT STUDY
OCTOBER 1, 2003 - SEPTEMBER 30, 2006 COST EVALUATION PERIOD
2004 RC FINAL PROPOSAL, $15m rf, 15-yr 02 bonds, CapReduc '03 3-17-03

Table C: Principal Payments (FY 2005)

Date	Transmission Bonds	Transmission Appropriations
9/30/2003	116,600.00	26,247.00
9/30/2004	115,906.00	39,817.01
9/30/2005	153,500.00	0.93
9/30/2006	140,000.00	11,249.03
9/30/2007	111,254.00	41,304.92
9/30/2008	112,119.00	42,412.54
9/30/2009	72,700.00	82,856.60
9/30/2010	89,933.00	67,009.34
9/30/2011	115,000.00	42,947.31
9/30/2012	40,000.00	118,344.37
9/30/2013	-	159,784.82
9/30/2014	59,050.00	102,049.13
9/30/2015	-	161,460.01
9/30/2016	148,847.23	10,987.99
9/30/2017	161,517.60	-
9/30/2018	153,498.43	-
9/30/2019	153,403.14	-
9/30/2020	152,574.54	-
9/30/2021	151,294.79	-
9/30/2022	149,644.19	-
9/30/2023	151,807.88	-
9/30/2024	144,499.45	-
9/30/2025	141,745.66	-
9/30/2026	138,622.41	-
9/30/2027	135,120.76	-
9/30/2028	135,528.93	-
9/30/2029	127,899.58	-
9/30/2030	121,381.06	-
9/30/2031	119,485.17	-
9/30/2032	114,441.71	-
9/30/2033	107,805.88	-
9/30/2034	100,986.26	-
9/30/2035	92,969.37	-
9/30/2036	85,282.48	-
9/30/2037	77,002.47	-
9/30/2038	68,089.00	-
9/30/2039	57,259.26	-
9/30/2040	47,179.36	-
9/30/2041	41,089.60	-
Total	4,205,038.21	906,471.00

TABLE A.3C

BONNEVILLE POWER ADMINISTRATION

TRANSMISSION REPAYMENT STUDY
OCTOBER 1, 2003 - SEPTEMBER 30, 2006 COST EVALUATION PERIOD
2004 RC FINAL PROPOSAL, $15m rf, 15-yr 02 bonds, CapReduc '03 3-17-03

Table D: Interest Payments (FY 2005)

Date	Transmission Bonds	Transmission Appropriations
9/30/2003	136,862.00	65,279.28
9/30/2004	154,099.00	63,483.99
9/30/2005	165,926.96	60,696.09
9/30/2006	169,235.93	60,696.03
9/30/2007	168,770.86	59,914.22
9/30/2008	169,795.50	56,978.96
9/30/2009	171,892.85	53,916.55
9/30/2010	176,587.12	47,900.54
9/30/2011	180,474.41	43,072.28
9/30/2012	183,230.05	39,980.58
9/30/2013	190,409.52	31,421.66
9/30/2014	200,722.73	19,859.14
9/30/2015	207,815.35	12,470.64
9/30/2016	221,181.54	792.24
9/30/2017	220,355.39	-
9/30/2018	228,446.57	-
9/30/2019	228,615.86	-
9/30/2020	229,517.46	-
9/30/2021	230,874.21	-
9/30/2022	232,603.81	-
9/30/2023	230,515.12	-
9/30/2024	237,900.55	-
9/30/2025	240,728.34	-
9/30/2026	243,920.59	-
9/30/2027	247,484.24	-
9/30/2028	247,130.07	-
9/30/2029	254,803.42	-
9/30/2030	261,357.94	-
9/30/2031	263,275.83	-
9/30/2032	268,321.29	-
9/30/2033	274,953.12	-
9/30/2034	281,744.74	-
9/30/2035	289,730.63	-
9/30/2036	297,375.52	-
9/30/2037	305,604.53	-
9/30/2038	314,448.94	-
9/30/2039	325,229.74	-
9/30/2040	335,255.64	-
9/30/2041	339,036.40	-
Total	9,126,233.77	616,462.20

File = TransRC2004-Final.sf-Trans 04RC-Final w/$15 RF,Mid-term Const,CapRed'03- SINGLE PURPOSE
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TABLE A.3D

BONNEVILLE POWER ADMINISTRATION

TRANSMISSION REPAYMENT STUDY
OCTOBER 1, 2003 - SEPTEMBER 30, 2006 COST EVALUATION PERIOD
2004 RC FINAL PROPOSAL, $15m rf, 15-yr 02 bonds, CapReduc '03 3-17-03

Table G: Summary of Payments (FY 2005)

Date	Transmission Principal Payment	Transmission Interest Payment
9/30/2003	142,847.00	202,141.28
9/30/2004	155,723.01	217,582.99
9/30/2005	153,500.93	226,623.05
9/30/2006	151,249.03	229,931.96
9/30/2007	152,558.92	228,685.08
9/30/2008	154,531.54	226,774.46
9/30/2009	155,556.60	225,809.40
9/30/2010	156,942.34	224,487.66
9/30/2011	157,947.31	223,546.69
9/30/2012	158,344.37	223,210.63
9/30/2013	159,784.82	221,831.18
9/30/2014	161,099.13	220,581.87
9/30/2015	161,460.01	220,285.99
9/30/2016	159,835.22	221,973.78
9/30/2017	161,517.60	220,355.39
9/30/2018	153,498.43	228,446.57
9/30/2019	153,403.14	228,615.86
9/30/2020	152,574.54	229,517.46
9/30/2021	151,294.79	230,874.21
9/30/2022	149,644.19	232,603.81
9/30/2023	151,807.88	230,515.12
9/30/2024	144,499.45	237,900.55
9/30/2025	141,745.66	240,728.34
9/30/2026	138,622.41	243,920.59
9/30/2027	135,120.76	247,484.24
9/30/2028	135,528.93	247,130.07
9/30/2029	127,899.58	254,803.42
9/30/2030	121,381.06	261,357.94
9/30/2031	119,485.17	263,275.83
9/30/2032	114,441.71	268,321.29
9/30/2033	107,805.88	274,953.12
9/30/2034	100,986.26	281,744.74
9/30/2035	92,969.37	289,730.63
9/30/2036	85,282.48	297,375.52
9/30/2037	77,002.47	305,604.53
9/30/2038	68,089.00	314,448.94
9/30/2039	57,259.26	325,229.74
9/30/2040	47,179.36	335,255.64
9/30/2041	41,089.60	339,036.40
Total	5,111,509.21	9,742,695.97

File = TransRC2004-Final.sf-Trans 04RC-Final w/$15 RF,Mid-term Const,CapRed'03- SINGLE PURPOSE
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TABLE A.3E

BONNEVILLE POWER ADMINISTRATION

TRANSMISSION REPAYMENT STUDY

OCTOBER 1, 2003 - SEPTEMBER 30, 2006 COST EVALUATION PERIOD

2004 RC FINAL PROPOSAL, $15m rf, 15-yr 02 bonds, CapReduc '03 3-17-03

Table H: Summary of Investments Placed in Service (1000s) (FY 2005)

Date	Unamortized Investment	Term Schedule
9/30/2002	6,636,250.58	5,688,062.00
9/30/2003	6,423,925.58	5,907,309.00
9/30/2004	6,255,646.59	6,126,439.00
9/30/2005	6,135,902.52	6,238,368.00
9/30/2006	6,175,477.55	6,194,303.00
9/30/2007	6,211,688.47	6,067,223.00
9/30/2008	6,245,641.01	6,064,770.00
9/30/2009	6,276,580.61	6,106,798.00
9/30/2010	6,304,892.95	6,119,168.00
9/30/2011	6,330,228.26	6,113,540.00
9/30/2012	6,351,873.63	6,168,934.00
9/30/2013	6,370,696.45	6,182,986.00
9/30/2014	6,386,423.58	6,078,945.00
9/30/2015	6,398,171.59	6,013,270.00
9/30/2016	6,404,058.81	5,932,571.00
9/30/2017	6,407,510.41	5,435,278.00
9/30/2018	6,399,036.84	5,353,572.00
9/30/2019	6,386,577.98	5,354,613.00
9/30/2020	6,369,428.52	5,436,081.00
9/30/2021	6,347,308.31	5,546,259.00
9/30/2022	6,320,053.50	5,675,147.00
9/30/2023	6,291,629.38	5,748,779.00
9/30/2024	6,252,773.83	5,932,134.00
9/30/2025	6,208,325.49	6,003,395.00
9/30/2026	6,158,193.90	6,192,149.00
9/30/2027	6,102,239.66	6,383,224.00
9/30/2028	6,044,529.59	6,464,163.00
9/30/2029	5,977,365.17	6,593,505.00
9/30/2030	5,902,084.23	6,655,889.00
9/30/2031	5,823,584.40	6,553,874.00
9/30/2032	5,738,903.11	6,204,097.00
9/30/2033	5,646,692.99	5,774,151.00
9/30/2034	5,547,224.25	5,716,206.00
9/30/2035	5,439,423.62	5,916,976.00
9/30/2036	5,323,717.10	6,117,965.00
9/30/2037	5,199,746.57	6,318,938.00
9/30/2038	5,067,046.57	6,167,230.00
9/30/2039	4,923,704.83	6,051,198.00
9/30/2040	4,852,586.39	5,983,844.00
9/30/2041	4,811,496.79	5,872,170.00
Total	240,448,641.61	240,453,523.00

ansRC2004-Final.sf-Trans 04RC-Final w/$15 RF,Mid-term Const,CapRed'03- SINGLE PURPOSE
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Table A.4

Application of Amortization
Transmission
FY 2005 Repayment Study

BONNEVILLE POWER ADMINISTRATION

TRANSMISSION REPAYMENT STUDY

OCTOBER 1, 2003 - SEPTEMBER 30, 2006 COST EVALUATION PERIOD

2004 RC FINAL PROPOSAL, $15m rf, 15-yr 02 bonds, CapReduc '03 3-17-03

APPLICATION OF AMORTIZATION (1000S) (FY 2005)

Date	Project	In Service	Due	Original Balance	Amount Available	Rate	Replacement?	Amount Amortized
FY 2003	BPA PROGRAM	2000	2003	15,300	15,300	6.850%	No	15,300
FY 2003	BONNEVILLE POWER ADMINISTRATION	1958	2003	15,593	15,593	6.840%	No	15,593
FY 2003	BONNEVILLE POWER ADMINISTRATION	1958	2003	10,654	10,654	6.840%	Yes	10,654
FY 2003	BPA PROGRAM	2000	2003	40,000	40,000	6.400%	No	40,000
FY 2003	BPA PROGRAM	1996	2003	54,378	54,378	5.900%	No	54,378
FY 2003	BPA PROGRAM	1995	2025	49,933	34,976	7.700%	No	6,922
SUB-TOTAL		-	-	185,858	170,901	-	Yes	142,847
FY 2004	BPA PROGRAM	2000	2004	39,052	39,052	7.000%	No	39,052
FY 2004	BONNEVILLE POWER ADMINISTRATION	1959	2004	8,157	8,157	6.880%	No	8,157
FY 2004	BONNEVILLE POWER ADMINISTRATION	1959	2004	8,863	8,863	6.880%	Yes	8,863
FY 2004	BPA PROGRAM	1997	2004	22,600	22,600	6.800%	No	22,600
FY 2004	BPA PROGRAM	1999	2004	26,200	26,200	5.950%	No	26,200
FY 2004	BONNEVILLE POWER ADMINISTRATION	1960	2005	3,598	3,598	6.910%	No	3,597
FY 2004	BONNEVILLE POWER ADMINISTRATION	1960	2005	4,218	4,218	6.910%	Yes	4,218
FY 2004	BONNEVILLE POWER ADMINISTRATION	1961	2006	11,271	11,271	6.950%	Yes	4,490
FY 2004	BONNEVILLE POWER ADMINISTRATION	1971	2016	17,805	17,805	7.290%	Yes	10,492
FY 2004	BPA PROGRAM	1995	2025	49,933	28,054	7.700%	No	28,054
SUB-TOTAL		-	-	191,697	169,818	-	Yes	155,723
FY 2005	BPA PROGRAM	2000	2005	53,500	53,500	7.150%	No	53,500
FY 2005	BONNEVILLE POWER ADMINISTRATION	1960	2005	3,598	1	6.910%	No	1
FY 2005	BPA PROGRAM	1997	2005	80,000	80,000	6.900%	No	80,000
FY 2005	BPA PROGRAM	2001	2005	20,000	20,000	5.650%	No	20,000
SUB-TOTAL		-	-	157,098	153,501	-	No	153,501
FY 2006	BPA PROGRAM	1996	2006	70,000	70,000	7.050%	No	70,000
FY 2006	BONNEVILLE POWER ADMINISTRATION	1961	2006	4,468	4,468	6.950%	No	4,468
FY 2006	BONNEVILLE POWER ADMINISTRATION	1961	2006	11,271	6,781	6.950%	Yes	6,781
FY 2006	BPA PROGRAM	2000	2006	40,000	40,000	6.750%	No	40,000
FY 2006	ENVIRONMENT	2002	2006	30,000	30,000	3.050%	No	30,000
SUB-TOTAL		-	-	155,739	151,249	-	Yes	151,249
FY 2007	BONNEVILLE POWER ADMINISTRATION	1962	2007	19,597	19,597	6.980%	No	19,597
FY 2007	BONNEVILLE POWER ADMINISTRATION	1962	2007	4,877	4,877	6.980%	Yes	4,877
FY 2007	BPA PROGRAM	1997	2007	111,254	111,254	6.650%	No	111,254
FY 2007	BONNEVILLE POWER ADMINISTRATION	1971	2016	12,051	12,051	7.290%	No	9,518
FY 2007	BONNEVILLE POWER ADMINISTRATION	1971	2016	17,805	7,313	7.290%	Yes	7,313
SUB-TOTAL		-	-	165,584	155,092	-	Yes	152,559
FY 2008	BONNEVILLE POWER ADMINISTRATION	1963	2008	4,876	4,876	7.020%	No	4,876
FY 2008	BONNEVILLE POWER ADMINISTRATION	1963	2008	4,330	4,330	7.020%	Yes	4,330
FY 2008	BONNEVILLE POWER ADMINISTRATION	1963	2008	904	904	7.020%	No	904
FY 2008	BONNEVILLE POWER ADMINISTRATION	1963	2008	803	803	7.020%	Yes	803
FY 2008	BPA PROGRAM	1998	2008	75,300	75,300	6.000%	No	75,300
FY 2008	BPA PROGRAM	1998	2008	36,819	36,819	5.750%	No	36,819
FY 2008	BONNEVILLE POWER ADMINISTRATION	1971	2016	12,025	12,025	7.290%	No	11,200
FY 2008	BONNEVILLE POWER ADMINISTRATION	1971	2016	17,766	17,766	7.290%	Yes	17,766
FY 2008	BONNEVILLE POWER ADMINISTRATION	1971	2016	12,051	2,533	7.290%	No	2,533
SUB-TOTAL		-	-	164,874	155,356	-	Yes	154,532
FY 2009	BONNEVILLE POWER ADMINISTRATION	1964	2009	4,151	4,151	7.060%	No	4,151
FY 2009	BONNEVILLE POWER ADMINISTRATION	1964	2009	5,738	5,738	7.060%	Yes	5,738
FY 2009	BPA PROGRAM	1998	2009	72,700	72,700	6.000%	No	72,700
FY 2009	BONNEVILLE POWER ADMINISTRATION	1971	2016	12,025	825	7.290%	No	825

FY 2009	BONNEVILLE POWER ADMINISTRATION	1972	2017	29,326	29,326	7.290%	No	29,326
FY 2009	BONNEVILLE POWER ADMINISTRATION	1972	2017	21,170	21,170	7.290%	Yes	21,170
FY 2009	BONNEVILLE POWER ADMINISTRATION	1972	2017	3,980	3,980	7.290%	No	3,980
FY 2009	BONNEVILLE POWER ADMINISTRATION	1972	2017	2,873	2,873	7.290%	Yes	2,873
FY 2009	BONNEVILLE POWER ADMINISTRATION	1973	2018	16,368	16,368	7.280%	No	4,303
FY 2009	BONNEVILLE POWER ADMINISTRATION	1973	2018	10,491	10,491	7.280%	Yes	10,491
SUB-TOTAL		-	-	178,822	167,622	-	Yes	155,557
FY 2010	BONNEVILLE POWER ADMINISTRATION	1965	2010	3,706	3,706	7.090%	No	3,706
FY 2010	BONNEVILLE POWER ADMINISTRATION	1965	2010	7,248	7,248	7.090%	Yes	7,248
FY 2010	BONNEVILLE POWER ADMINISTRATION	1965	2010	5,202	5,202	7.090%	No	5,202
FY 2010	BONNEVILLE POWER ADMINISTRATION	1965	2010	10,171	10,171	7.090%	Yes	10,171
FY 2010	ENVIRONMENT	2001	2010	30,000	30,000	6.050%	No	30,000
FY 2010	BPA PROGRAM	2001	2010	59,933	59,933	6.050%	No	59,933
FY 2010	BONNEVILLE POWER ADMINISTRATION	1973	2018	33,788	33,788	7.280%	No	6,961
FY 2010	BONNEVILLE POWER ADMINISTRATION	1973	2018	21,656	21,656	7.280%	Yes	21,656
FY 2010	BONNEVILLE POWER ADMINISTRATION	1973	2018	16,368	12,065	7.280%	No	12,065
SUB-TOTAL		-	-	188,072	183,769	-	Yes	156,942
FY 2011	BONNEVILLE POWER ADMINISTRATION	1966	2011	11,830	11,830	7.130%	No	11,830
FY 2011	BONNEVILLE POWER ADMINISTRATION	1966	2011	3,049	3,049	7.130%	Yes	3,049
FY 2011	BONNEVILLE POWER ADMINISTRATION	1966	2011	6,647	6,647	7.130%	No	6,647
FY 2011	BONNEVILLE POWER ADMINISTRATION	1966	2011	1,714	1,714	7.130%	Yes	1,714
FY 2011	BPA PROGRAM	1998	2011	40,000	40,000	6.200%	No	40,000
FY 2011	BPA PROGRAM	2001	2011	25,000	25,000	5.950%	No	25,000
FY 2011	BPA PROGRAM	2001	2011	50,000	50,000	5.750%	No	50,000
FY 2011	BONNEVILLE POWER ADMINISTRATION	1973	2018	33,788	26,827	7.280%	No	19,707
SUB-TOTAL		-	-	172,028	165,067	-	Yes	157,947
FY 2012	BONNEVILLE POWER ADMINISTRATION	1967	2012	19,003	19,003	7.160%	No	19,003
FY 2012	BONNEVILLE POWER ADMINISTRATION	1967	2012	4,566	4,566	7.160%	Yes	4,566
FY 2012	BONNEVILLE POWER ADMINISTRATION	1967	2012	14,300	14,300	7.160%	No	14,300
FY 2012	BONNEVILLE POWER ADMINISTRATION	1967	2012	3,436	3,436	7.160%	Yes	3,436
FY 2012	ENVIRONMENT	1997	2012	40,000	40,000	6.950%	No	40,000
FY 2012	BONNEVILLE POWER ADMINISTRATION	1970	2015	64,977	64,977	7.270%	No	34,510
FY 2012	BONNEVILLE POWER ADMINISTRATION	1970	2015	7,995	7,995	7.270%	Yes	7,995
FY 2012	BONNEVILLE POWER ADMINISTRATION	1970	2015	24,412	24,412	7.270%	No	24,412
FY 2012	BONNEVILLE POWER ADMINISTRATION	1970	2015	3,003	3,003	7.270%	Yes	3,003
FY 2012	BONNEVILLE POWER ADMINISTRATION	1973	2018	33,788	7,119	7.280%	No	7,119
SUB-TOTAL		-	-	215,480	188,811	-	Yes	158,344
FY 2013	BONNEVILLE POWER ADMINISTRATION	1968	2013	41,070	41,070	7.200%	No	41,070
FY 2013	BONNEVILLE POWER ADMINISTRATION	1968	2013	8,076	8,076	7.200%	Yes	8,076
FY 2013	BONNEVILLE POWER ADMINISTRATION	1968	2013	23,202	23,202	7.200%	No	23,202
FY 2013	BONNEVILLE POWER ADMINISTRATION	1968	2013	4,562	4,562	7.200%	Yes	4,562
FY 2013	BONNEVILLE POWER ADMINISTRATION	1970	2015	64,977	30,467	7.270%	No	30,467
FY 2013	BONNEVILLE POWER ADMINISTRATION	1974	2019	20,984	20,984	7.270%	Yes	18,019
FY 2013	BONNEVILLE POWER ADMINISTRATION	1974	2019	12,563	12,563	7.270%	No	12,563
FY 2013	BONNEVILLE POWER ADMINISTRATION	1974	2019	21,826	21,826	7.270%	Yes	21,826
SUB-TOTAL		-	-	197,260	162,750	-	Yes	159,785
FY 2014	BONNEVILLE POWER ADMINISTRATION	1969	2014	42,237	42,237	7.230%	No	42,237
FY 2014	BONNEVILLE POWER ADMINISTRATION	1969	2014	22,537	22,537	7.230%	Yes	22,537
FY 2014	BONNEVILLE POWER ADMINISTRATION	1969	2014	384	384	7.230%	No	384
FY 2014	BONNEVILLE POWER ADMINISTRATION	1969	2014	205	205	7.230%	Yes	205
FY 2014	BPA PROGRAM	1999	2014	59,050	59,050	5.900%	No	59,050
FY 2014	BONNEVILLE POWER ADMINISTRATION	1974	2019	12,079	12,079	7.270%	No	12,079
FY 2014	BONNEVILLE POWER ADMINISTRATION	1974	2019	20,984	2,965	7.270%	Yes	2,965
FY 2014	BONNEVILLE POWER ADMINISTRATION	1975	2020	17,158	17,158	7.250%	No	9,900
FY 2014	BONNEVILLE POWER ADMINISTRATION	1975	2020	11,742	11,742	7.250%	Yes	11,742
SUB-TOTAL		-	-	186,376	168,357	-	Yes	161,099
FY 2015	BONNEVILLE POWER ADMINISTRATION	1970	2015	64,977	-0	7.270%	No	-0
FY 2015	BONNEVILLE POWER ADMINISTRATION	1975	2020	32,026	32,026	7.250%	No	32,026

FY 2015	BONNEVILLE POWER ADMINISTRATION	1975	2020	21,916	21,916	7.250%	Yes	21,916
FY 2015	BONNEVILLE POWER ADMINISTRATION	1975	2020	17,158	7,258	7.250%	No	7,258
FY 2015	BONNEVILLE POWER ADMINISTRATION	1976	2021	61,025	61,025	7.230%	No	61,025
FY 2015	BONNEVILLE POWER ADMINISTRATION	1976	2021	2,212	2,212	7.230%	Yes	2,212
FY 2015	BONNEVILLE POWER ADMINISTRATION	1977	2022	33,702	33,702	7.210%	No	32,042
FY 2015	BONNEVILLE POWER ADMINISTRATION	1977	2022	4,981	4,981	7.210%	Yes	4,981
SUB-TOTAL		-	-	237,997	163,120	-	Yes	161,460
FY 2016	BONNEVILLE POWER ADMINISTRATION	1971	2016	12,025	-0	7.290%	No	-0
FY 2016	BONNEVILLE POWER ADMINISTRATION	1971	2016	12,051	0	7.290%	No	0
FY 2016	BONNEVILLE POWER ADMINISTRATION	1971	2016	17,805	0	7.290%	Yes	0
FY 2016	BPA PROGRAM	2002	2017	108,010	108,010	6.060%	No	106,492
FY 2016	BONNEVILLE POWER ADMINISTRATION	1977	2022	3,948	3,948	7.210%	No	3,948
FY 2016	BONNEVILLE POWER ADMINISTRATION	1977	2022	5,380	5,380	7.210%	Yes	5,380
FY 2016	BONNEVILLE POWER ADMINISTRATION	1977	2022	33,702	1,660	7.210%	No	1,660
FY 2016	BPA PROGRAM	2004	2039	316,633	316,633	7.180%	No	42,355
SUB-TOTAL		-	-	509,554	435,631	-	Yes	159,835
FY 2017	BPA PROGRAM	2002	2017	60,000	60,000	6.060%	No	60,000
FY 2017	BPA PROGRAM	2002	2017	100,000	100,000	6.060%	No	100,000
FY 2017	BPA PROGRAM	2002	2017	108,010	1,518	6.060%	No	1,518
SUB-TOTAL		-	-	268,010	161,518	-	No	161,518
FY 2018	BONNEVILLE POWER ADMINISTRATION	1973	2018	16,368	0	7.280%	No	0
FY 2018	ENVIRONMENT	2003	2018	2,675	2,675	6.560%	No	2,675
FY 2018	BPA PROGRAM	2004	2039	316,633	274,278	7.180%	No	150,823
SUB-TOTAL		-	-	335,676	276,953	-	No	153,498
FY 2019	BONNEVILLE POWER ADMINISTRATION	1974	2019	20,984	0	7.270%	Yes	0
FY 2019	ENVIRONMENT	2004	2019	7,369	7,369	6.770%	No	7,369
FY 2019	BPA PROGRAM	2004	2039	316,633	123,455	7.180%	No	123,455
FY 2019	BPA PROGRAM	2005	2040	267,831	267,831	7.100%	No	22,579
SUB-TOTAL		-	-	612,817	398,655	-	Yes	153,403
FY 2020	ENVIRONMENT	2005	2020	5,414	5,414	6.690%	No	5,414
FY 2020	BPA PROGRAM	2005	2040	267,831	245,252	7.100%	No	147,161
SUB-TOTAL		-	-	273,245	250,666	-	No	152,575
FY 2021	BPA PROGRAM	2005	2040	267,831	98,091	7.100%	No	98,091
FY 2021	BPA PROGRAM	2006	2041	111,674	111,674	7.100%	Yes	53,204
SUB-TOTAL		-	-	379,505	209,765	-	Yes	151,295
FY 2022	BONNEVILLE POWER ADMINISTRATION	1977	2022	33,702	-0	7.210%	No	-0
FY 2022	BPA PROGRAM	2006	2041	111,674	58,470	7.100%	Yes	58,470
FY 2022	BPA PROGRAM	2007	2042	116,348	116,348	7.100%	Yes	91,174
SUB-TOTAL		-	-	261,724	174,818	-	Yes	149,644
FY 2023	BPA PROGRAM	1998	2023	106,600	106,600	5.850%	No	106,600
FY 2023	BPA PROGRAM	2007	2042	116,348	25,174	7.100%	Yes	25,174
FY 2023	BPA PROGRAM	2008	2043	120,579	120,579	7.100%	Yes	20,034
SUB-TOTAL		-	-	343,527	252,353	-	Yes	151,808
FY 2024	BPA PROGRAM	2008	2043	120,579	100,545	7.100%	Yes	100,545
FY 2024	BPA PROGRAM	2009	2044	124,617	124,617	7.100%	Yes	43,954
SUB-TOTAL		-	-	245,196	225,162	-	Yes	144,499
FY 2025	BPA PROGRAM	2009	2044	124,617	80,663	7.100%	Yes	80,663
FY 2025	BPA PROGRAM	2010	2045	128,630	128,630	7.100%	Yes	61,083
SUB-TOTAL		-	-	253,247	209,293	-	Yes	141,746
FY 2026	BPA PROGRAM	2010	2045	128,630	67,547	7.100%	Yes	67,547
FY 2026	BPA PROGRAM	2011	2046	132,612	132,612	7.100%	Yes	71,075
SUB-TOTAL		-	-	261,242	200,159	-	Yes	138,622

FY 2027 BPA PROGRAM	2011	2046	132,612	61,537	7.100%	Yes	61,537
FY 2027 BPA PROGRAM	2012	2047	136,699	136,699	7.100%	Yes	73,584
SUB-TOTAL	-	-	269,311	198,236	-	Yes	135,121
FY 2028 BPA PROGRAM	1998	2028	112,300	112,300	5.850%	No	112,300
FY 2028 BPA PROGRAM	2012	2047	136,699	63,115	7.100%	Yes	23,229
SUB-TOTAL	-	-	248,999	175,415	-	Yes	135,529
FY 2029 BPA PROGRAM	1998	2029	50,000	50,000	6.650%	No	50,000
FY 2029 BPA PROGRAM	2012	2047	136,699	39,886	7.100%	Yes	39,886
FY 2029 BPA PROGRAM	2013	2048	140,962	140,962	7.100%	Yes	38,014
SUB-TOTAL	-	-	327,661	230,848	-	Yes	127,900
FY 2030 BPA PROGRAM	1994	2034	50,000	50,000	7.050%	No	3,735
FY 2030 BPA PROGRAM	2013	2048	140,962	102,948	7.100%	Yes	102,948
FY 2030 BPA PROGRAM	2014	2049	145,372	145,372	7.100%	Yes	14,698
SUB-TOTAL	-	-	336,334	298,320	-	Yes	121,381
FY 2031 BPA PROGRAM	1993	2033	110,000	110,000	6.950%	No	44,998
FY 2031 BPA PROGRAM	1994	2034	50,000	46,265	7.050%	No	46,265
FY 2031 BPA PROGRAM	2003	2038	352,497	352,497	7.010%	No	28,222
SUB-TOTAL	-	-	512,497	508,762	-	No	119,485
FY 2032 BPA PROGRAM	1998	2032	98,900	98,900	6.700%	No	98,900
FY 2032 BPA PROGRAM	1993	2033	110,000	65,002	6.950%	No	15,522
FY 2032 BPA PROGRAM	2003	2038	352,497	324,275	7.010%	No	19
SUB-TOTAL	-	-	561,397	488,177	-	No	114,442
FY 2033 BPA PROGRAM	1993	2033	110,000	49,479	6.950%	No	49,479
FY 2033 BPA PROGRAM	1994	2034	108,400	108,400	6.850%	No	58,327
SUB-TOTAL	-	-	218,400	157,879	-	No	107,806
FY 2034 BPA PROGRAM	1994	2034	50,000	-0	7.050%	No	-0
FY 2034 BPA PROGRAM	1994	2034	50,000	50,000	6.850%	No	50,000
FY 2034 BPA PROGRAM	1994	2034	108,400	50,073	6.850%	No	50,073
FY 2034 BPA PROGRAM	2003	2038	352,497	324,256	7.010%	No	913
SUB-TOTAL	-	-	560,897	424,330	-	No	100,986
FY 2035 BPA PROGRAM	2003	2038	352,497	323,343	7.010%	No	92,969
SUB-TOTAL	-	-	352,497	323,343	-	No	92,969
FY 2036 BPA PROGRAM	2003	2038	352,497	230,374	7.010%	No	85,282
SUB-TOTAL	-	-	352,497	230,374	-	No	85,282
FY 2037 BPA PROGRAM	2003	2038	352,497	145,091	7.010%	No	77,002
SUB-TOTAL	-	-	352,497	145,091	-	No	77,002
FY 2038 BPA PROGRAM	2003	2038	352,497	68,089	7.010%	No	68,089
SUB-TOTAL	-	-	352,497	68,089	-	No	68,089
FY 2039 BPA PROGRAM	2004	2039	316,633	-0	7.180%	No	-0
FY 2039 BPA PROGRAM	2014	2049	145,372	130,674	7.100%	Yes	57,259
SUB-TOTAL	-	-	462,005	130,674	-	Yes	57,259
FY 2040 BPA PROGRAM	2014	2049	145,372	73,415	7.100%	Yes	47,179
SUB-TOTAL	-	-	145,372	73,415	-	Yes	47,179
FY 2041 BPA PROGRAM	2006	2041	111,674	-0	7.100%	Yes	-0
FY 2041 BPA PROGRAM	2014	2049	145,372	26,235	7.100%	Yes	26,235
FY 2041 BPA PROGRAM	2015	2050	149,712	149,712	7.100%	Yes	14,854
SUB-TOTAL	-	-	406,758	175,947	-	Yes	41,090
GRAND TOTAL	-	-	11,600,247	8,579,287	-	Yes	5,111,509

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APPENDIX B

PROGRAMS IN REVIEW CLOSE-OUT LETTER

Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

EXECUTIVE OFFICE

December 19, 2002

In reply refer to: TMC-Ditt-2

Dear Programs in Review Participant:

Subject: Close out of the public process and final report on the Transmission Business Line's Programs In Review regarding expense and capital spending - Fiscal Years 2004 and 2005

This report summarizes Bonneville Power Administration's (BPA) discussions with customers during the Transmission Business Line's (TBL) Programs in Review (PIR) process regarding proposed program level expenditures for Fiscal Years (FY) 2004 and 2005, and includes TBL's program level decisions.

Five regional workshops were held during July 2002 to discuss TBL's proposed capital and expense program levels for these two fiscal years. At the customers' request, an additional workshop was held in Portland, Oregon in September so staff could provide details of the proposed program levels.

During the course of these workshops, TBL continued to evaluate spending levels for both capital and expense programs to be as efficient and cost effective as possible, while still maintaining the program levels required to operate a reliable transmission system and meet the challenges of a competitive marketplace.

The PIR process looked at expense and capital levels for a three-year period covering FY 2004-2006, so that TBL would have the flexibility to set rates for a one, two or three year rate period. A two-year rate period is proposed, so the PIR decisions presented cover two years, FY 2004-2005, of TBL expense and capital spending.

At the initial July PIR workshops, the TBL proposed an average annual expense estimate of $374 million for the FY 2004-2005 period. However, based on discussions with customers and TBL's subsequent internal review, TBL has reduced overall expenses by about $17.5 million annually. The TBL's proposed capital program included spending levels of $327M and $280M for FY2004 and FY2005, respectively.

Reducing spending levels

In the July workshops, TBL demonstrated how we substantially reduced capital and expense spending over the past two years. TBL has made significant progress in continuing to control its spending through management and efficiency efforts. TBL also outlined the issues currently facing the transmission industry and how these issues could drive future costs upward.

Over the past 10 years, TBL has cut back on transmission upgrades and expansions, using innovative technologies and techniques to meet customer needs and market demands. This technology allowed us to absorb growth while still maintaining reliability. But, it also meant that TBL had to accept more risk and push our system harder.

Due to load growth throughout the region and increased transactions enabled by market deregulation, the operating margin we once had is now gone. The system is approaching capacity and significant constraints could begin to affect access to the system.

In the coming years, TBL must look at ways to build new lines and upgrade existing transmission to maintain the transmission system's adequacy, reliability and availability. This must be accomplished in the face of increased regional load growth, congested pathways, a greater number of transactions and the related system improvements required to meet these needs, while working to integrate additional generation into the system.

Capital program

Comments received from customers were helpful to us in finalizing our proposed spending levels for the coming years. Comments were generally supportive of spending for proposed infrastructure improvements to continue to maintain reliability of the transmission system. However, this support was conditioned on receiving an assurance that TBL would manage the risks of building the infrastructure projects as related to reliability and that new generators, who directly benefit from the construction of new infrastructure, would prepay for those improvements to the system. We also received some comments about the need to reduce planned program costs while assigning costs directly to any party who benefits from the planned actions. Other comments questioned rising costs in certain areas, such as implementation of a Regional Transmission Organization (RTO), accommodating deregulation, and shifts in redispatch charges.

During the discussion on program levels, some policy issues arose. One focused on the need for proposed transmission improvements and additions, and specifically asked for clarification on who would pay for transmission investments under various construction scenarios. We were also asked about TBL's policy in relation to non-federal funding for infrastructure. Some comments on this issue had to do with practices already decided by BPA, such as those covered in the TBL's Direct Assignment Guidelines. Other comments addressed whether TBL's list of infrastructure projects was still relevant in today's quickly changing electricity industry and how customers could be assured that there is adequate evaluation of project need.

In response, TBL is continuing to move forward on several of the proposed infrastructure projects for varying reasons. These include three proposed transmission line projects to relieve congestion and maintain reliability of the system: Kangley-Echo Lake 500-kV Transmission Line, Shultz-Hanford Area 500-kV Transmission Line, and Grand Coulee-Bell 500-kV

Transmission Line (Eastern Washington Reinforcement). Work is continuing on two other projects, the installation of the Shultz Series Capacitors and the Celilo modernization project. Both of these projects will reinforce the existing transmission system without building new lines. Two other proposed transmission infrastructure projects to enable integration of new generators would only move forward if non-federal funding was secured. These projects are McNary-John Day 500-kV Transmission Line and the Southwest Washington-Northwest Oregon Reinforcement.

We are presently seeking payments in advance from generators in return for future transmission credits. This approach assures that BPA and the region do not run the risk of having stranded investment if the generators decide to delay or cancel their projects. We will continue to act consistent with FERC's policy as it evolves. We will also continue to monitor the situation to understand how this affects generation construction.

We are continuing to investigate how to effectively integrate non-transmission alternatives into our transmission planning process. Before TBL decides to build a line, we want to make sure we have evaluated all feasible alternatives. This could include non-wire alternatives such as energy efficiency programs, demand reduction initiatives, and pricing strategies, among other options. We are currently seeking input from a regional stakeholders group as part of our normal planning process to determine how to best accomplish this goal. We expect to hold our first discussion in early 2003.

I want to assure you that TBL is committed to identifying regional reliability issues, proposing solutions, and using all available mechanisms to find economic and equitable solutions to maintaining the transmission system. As part of this commitment, TBL will continue to facilitate the regional technical dialogue through the established Regional Technical Review Teams to better define the prioritization, costs and need for transmission projects. Thanks to this effort, TBL and the region have developed an annual review process to update the proposed transmission project list and assist in keeping costs under control.

Expense program levels

TBL is holding operating cost increases to a level that are less than the rate of inflation. In order to keep program levels as low as possible, TBL has cut about $17.5 million per year in operating costs. TBL must also recognize cost increases of $2.3 million associated with adjusted employee benefits loading rates. These changes will result in an average annual operating expense budget of $356.5 million. These cuts will be difficult, but TBL is committed to making reductions in labor, materials, and contracts to achieve the proposed spending levels. By operating program, the changes include:

Transmission System Maintenance	($7.6 million)
Transmission G&A	($5.0 million)
Transmission System Operations	($2.6 million)

Transmission Support Services	($1.8 million)
Transmission System Development	($0.9 million)
Wheeling/Leases	$0.1 million
Transmission Scheduling	($0.2 million)
Transmission Marketing	$0.6 million
Total Reductions	**($17.5 million)**

Participation in RTO West

We received several comments from customers about the level of BPA's involvement in RTO West. We continue to see RTO West as a viable alternative for the future if certain conditions are met, and therefore, will continue to allocate resources at current levels to participate in its formation. The decision on whether to join an RTO will not be made until after a full vetting of the issues in a different public forum. Although one customer suggested BPA wait and let an RTO make all the needed infrastructure improvements, we must continue to meet our obligation to allocate resources to plan and build needed transmission infrastructure. Since we have yet to decide whether BPA would join an RTO, we must continue to make the necessary investments in our system. We are committed to participating in the development of an RTO that works for the Northwest. Toward that goal, we included RTO West costs for FY 2004-2005 at $2.6 million a year.

Issues to be covered in the rate case

Certain issues that were identified during the PIR process such as redispatch expense and revenue financing are considered rate case issues and therefore will be discussed and covered in that forum.

Finalizing TBL program levels

Today TBL faces critical issues:

- Operating and maintaining its aging transmission system
- Building a business framework in a changing environment
- Constructing transmission infrastructure to meet load growth
- Determining contractual reliability and resource integration demands
- Maintaining a skilled and trained workforce
- Access to limited capital borrowing authority.

The proposed TBL capital and expense spending levels for FY 2004-2005 reflect TBL decisions on how we will move forward to resolve these critical issues. Our direction will continue to be influenced by feedback from our customers and constituents. Through the PIR process, you have helped us hone our proposed spending levels and better understand alternatives available to us.

We appreciate your comments and input. We remain committed to these open public processes where ideas can flow freely for the region's benefit. Thank you again for your participation in TBL's PIR process.

Sincerely,

/S/

Stephen J. Wright
Administrator and
Chief Executive Officer

2 Enclosures:
Appendix 1 – TBL Expense Levels – Programs in Review
Appendix 2 – TBL Capital Program – Programs in Review

TBL Expense Levels - Programs In Review ($ in thousands)

Program & Other Operating Costs	Averages Across FY 2004-05		
	Initial PIR	**Final PIR**	**Savings**
Transmission G&A	22,701.3	17,699.3	**(5,002.0)**
CSRS Pension Expense	14,350.0	14,350.0	**0.0**
Transmission Marketing	15,004.1	15,565.5	**561.4**
Transmission Scheduling	8,705.9	8,473.1	**(232.8)**
Transmission System Operations	40,563.0	37,922.8	**(2,640.2)**
Transmission System Maintenance	88,633.8	80,995.6	**(7,638.1)**
Transmission System Development	13,885.4	12,983.9	**(901.5)**
Wheeling/Leases	5,973.8	6,105.4	**131.6**
Environment (Includes Environment Org)	4,538.9	4,551.1	**12.2**
Transmission Support Services	19,603.3	17,854.9	**(1,748.5)**
Total System O & M	**233,959.4**	**216,501.4**	**(17,458.0)**
Between Business Line Expenses			
Ancillary Services	71,495.3	71,495.3	**0.0**
Corps/Bureau/Network/Delivery Facilities	4,084.0	4,084.0	**0.0**
Station Service	1,723.6	1,723.6	**0.0**
Total BBL Expense	**77,302.9**	**77,302.9**	**0.0**
Corporate Expenses			
Legal Support - Expense	2,023.0	2,023.0	**0.0**
Shared Services Costs	37,355.0	37,355.0	**0.0**
Corporate Overhead Distributions	23,360.0	23,360.0	**0.0**
Total Corporate Charges	**62,738.0**	**62,738.0**	**0.0**
Total Transmission Operating Expense	**374,000.3**	**356,542.3**	**(17,458.0)**

TBL - Capital Program
FY2004 and FY2005 Projections
($ in Thousands)

	G-PROJECT	Need Date	FY 2004	FY 2005
MAIN GRID				
Project Name				
Puget Sound Area Additions	G-1	2004	7,368.7	0.0
Schultz-Wautoma 500 kV line	G-2	2004	50,138.9	0.0
McNary-John Day 500 kV line	G-3	2004	0.0	0.0
Low Mon-Starbucks 500 kV	G-4	2004	0.0	10,904.7
McNary-Smiths Harbor 500 kV	G-5	2004	0.0	0.0
Schultz 500 KV series caps	G-6	2003	3,000.1	0.0
Echo Lake-Monroe 500 kV	G-8	2007	0.0	5,414.4
Coulee-Bell 500 kV (WOH Ph 1)	G-9	2004	61,255.2	0.0
Line Relocation (Nisqually Reservation)			0.0	0.0
Line Relocations on Tribal Lands			3,158.0	3,248.7
Columbia Falls - Kerr Reconductor			0.0	0.0
Seattle Area 500/230 kV Bank	G-11	2006	0.0	1,082.9
Pearl 500/230 KV bank	G-10	2003	0.0	0.0
Chemawa 230/115 kV Bank			0.0	0.0
Santiam-Bethel Tap 230 Line #2			0.0	0.0
Olympia 230/115KV Bank #3			0.0	0.0
Olympia-Shelton 500KV	G-12	2006	252.6	10,828.9
Fairmount Shunt Cap			0.0	0.0
Shelton-Fairmount 230KV line			0.0	0.0
Hanford-Ost. tap to Big Eddy	G-14	2008	1,052.7	3,248.7
N. Cross Cascades SC 500 KV			0.0	5,414.4
Ponderosa 500/230 KV bk #2			0.0	0.0
North Noxon Reinforcement (WOH Ph1)	G-20	2007	631.6	7,580.2
L Goose-Starbucks 500 kV (WOH Ph2)	G-17	2008	0.0	0.0
Big -Eddy-Ostrander 500KV			0.0	0.0
McNary-Brownlee 230 KV (PNW-ID)	G-19	2006	6,316.1	33,569.5
Hatwai-Lolo 230 kV (PNW-ID)	G-18	2007	0.0	0.0
McNary-Tap on Ashe-Marion 500 kV	G-16	2007	421.1	6,497.3
N. Idaho Reinforcement (Lib-Bonners)	G-15	2007	0.0	584.8
Walla Walla 115/69 Bank Repl			0.0	0.0
Santiam-Chemawa 230 Line#2			0.0	0.0
Other Associated gen Integration			3,158.0	4,331.5
NERC Criteria Compliance			2,105.4	2,165.8
Fire Suppression			0.0	0.0
System Reactive Facilities			5,000.0	5,000.0
Various Additions			5,000.0	5,000.0
Total Main Grid			**148,858.4**	**104,871.7**
AREA & CUSTOMER SERVICE				
Project Name				
Albany-Eugene Rebuild			0.0	0.0
Kitsap Penin Reinf			0.0	0.0
Red Mountain 115 kV Sub			0.0	0.0
Walla Walla 115/69 Bank Repl			0.0	0.0
Franklin Area Reinf (recond)			0.0	0.0
SW Ore Coast (Bandon-Rogue)			315.8	1,840.9
Goshen-Drummond Upgrade&Tx			0.0	0.0
Trentwood 230/115kv bk/line			0.0	0.0
Fairview SVC			0.0	0.0
Vintage Valley			0.0	0.0
Port Angeles SVC			0.0	0.0

TBL - Capital Program
FY2004 and FY2005 Projections
($ in Thousands)

	G-PROJECT	Need Date	FY 2004	FY 2005
Harney system 138 kV upgrade			0.0	0.0
Driscoll/Clatsop 230/115KV Tx			0.0	0.0
Longview 230/115-kV Bank #2			105.3	541.4
Redmond 230/115KV Bank #2			0.0	0.0
Palisades-Snake River 115 line			0.0	108.3
Palisades-Goshen 161KV line/TX			1,052.7	4,331.5
East Omak 230/115KV Bank			0.0	0.0
Libby-Bonners Ferry 115 Recond			0.0	0.0
Libby-Troy Line Purchase			0.0	0.0
Minidoka Substation Reguild			0.0	0.0
Victor Tap - Goab Switch			0.0	0.0
Alvey-Eugene 1 & 2 TT Addition			0.0	0.0
Addy Sub - Retire Delivery Facilities			0.0	0.0
Potholes Sub - 115KV Bus Tie Addition			126.3	0.0
Duckabush Sub - Repl. Transf.			0.0	0.0
Hampton Sub - Repl. Transf.			0.0	0.0
Vintage Valley- 230 & 115 KV Term. Add.			0.0	0.0
Red Mtn.- 2-115 KV Terminal Add.			1,052.7	0.0
McNary Sub - 115 KV Term. (Benton PUD)			421.1	0.0
Metering Data Upgrade - BPA System			1,052.7	0.0
White Bluffs-Richland -relocate 1 mile			105.3	0.0
substation X (U.S. Navy)			0.0	0.0
Misc. Line Upgrade/Cap Additions for Wind Projects			4,210.7	3,032.1
Customer Service Items			2,947.5	3,248.7
Total Area & Customer Srvc			**11,074.1**	**11,262.0**
UPGRADES & ADDITIONS				
Project Name				
System Controls			10,526.8	12,994.6
Business System Develop.			8,474.0	8,663.1
Trans. System IT Develop.			4,210.7	5,414.4
Ftathead Valley Reinf (RAS)			0.0	0.0
Fiber Optics (Incls Terminations)			13,684.8	12,994.6
Misc Line & Sub Additions			3,158.0	3,248.7
Total Upgrades & Additions			**40,054.3**	**43,315.5**
SYSTEM REPLACEMENTS				
Project Name				
Nonelectric Plant Replcmts			6,316.1	6,497.3
Transmission Line Replcmts			0.0	0.0
Substation Replcmts			0.0	0.0
System Protection Replcmts			0.0	0.0
Pwr Sys Cntrl Replcmts			0.0	0.0
Total M3C, M4C, M5C, M6C			13,684.8	12,994.6
Celilo upgrades	G-7	2003	6,642.4	0.0
Tools and Equipment			5,500.0	5,000.0
Emergency Funds			10,000.0	10,000.0
Total System Replacements			**42,143.2**	**34,492.0**
ENVIRONMENT				

TBL - Capital Program
FY2004 and FY2005 Projections
($ in Thousands)

	G-PROJECT	Need Date	FY 2004	FY 2005
Project Name				
PP&A--Fire Prot/Sec Contain				0.0
PP&A--PCB Capacitor Replac				0.0
PP&A--Restoration				0.0
Total VR2C, VR4C, VR7C			7,368.7	5,414.4
Cap ADP Equip--Environment			0.0	0.0
Total Environment (PP&A)			**7,368.7**	**5,414.4**
ALL OTHER DIRECT CAPITAL				
Project Name				
Capital ADP Equipment			736.9	758.0
Completion of Prior Yr Items			100.0	100.0
Cap-to-Exp Adjustments			(3,000.0)	(3,000.0)
Undistributed Funding (Reduction)			0.0	0.0
Total All Other Capital			**(2,163.1)**	**(2,142.0)**
SUB TOTAL TBL CAPITAL (DIRECT)			**247,651.4**	**199,054.5**
INDIRECTS				
TSD Program Indirect			20,802.4	21,322.4
TSD MS&A			8,405.0	8,615.1
Support Services Cap Distribution			10,086.0	10,338.2
Total TBL Indirects			**39,293.4**	**40,275.7**
AFUDC				
AFUDC			22,957.0	23,148.0
Total AFUDC			**22,957.0**	**23,148.0**
CORPORATE OVERHEAD *1/*				
Corporate Distributions			7,080.0	7,300.0
Corporate Shared Services			9,910.0	10,380.0
Corporate Legal Support			98.2	100.7
Total Corporate Overhead			**17,088.2**	**17,780.7**
SUB TOTAL TBL CAPITAL (INDIRECT)			**79,338.6**	**81,204.4**
TOTAL TBL CAPITAL			**326,990.0**	**280,258.9**
Non-Borrowing Authority Items				
Plant Funded from Revenues				
Paul-Troutdale 500 kV	G-13	2005	51,581.1	54,761.6
McNary-Smiths Harbor 500 kV	G-5	2004	9,474.1	0.0
McNary-John Day 500 kV line	G-3	2004	47,370.4	0.0
Total Plant Funded from Revenues			**108,425.5**	**54,761.6**
Projects Funded in Advance			20,000.0	20,000.0
Smiths Harbor Sub/Line			5,600.0	0.0
Retirements/Sale of Facilities			5,000.0	5,000.0
Total Non-Borrowing Authority Items			**30,600.0**	**25,000.0**
TOTAL TBL CAPITAL			**466,015.5**	**360,020.5**

Bonneville Power Administration

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